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EVALUATION OF CRITERIA FOR TRANSMISSION CAPACITY CALCULATION

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ABSTRACT

Jani Stenroos: Evaluation of Criteria for Transmission Capacity Calculation
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Voltage and angle stability along with the thermal loadability of the transmission lines are limiting the transmission capacity of the Nordic power system. Voltage stability after a dimensioning fault limits the transmission capacity of the Finnish power system when power is imported from Sweden to Finland. When power is exported from Finland to Sweden, the damping of the inter-area electromechanical oscillations is the transmission capacity limiting factor. The oscillations appear in many power system quantities, but they are usually referred to as the power oscillations.

In transmission capacity calculation, limiting values for the operation of the power system are used as calculation criteria, which determine the allowed operating conditions. The effects of choosing the limits for voltage stability and damping of power oscillations on the transmission capacity and security margins of the Finnish power system are examined in this thesis. The transmission capacity calculation criteria are applied in various operating conditions, and it is examined how the transmission capacity and security margins would change if different criteria were used. The research methods include load flow- and dynamics calculation. In addition, the damping of the power oscillations is examined utilizing the Prony's method.

The research indicated that decreasing the limit for voltage stability would increase the transmission capacity but decrease the security margins. The transmission capacity was discovered to differ between various operating conditions considerably. On the other hand, smaller fluctuation was observed in the security margins between various operating conditions. Based on the studied operating conditions, the security of the Finnish power system does not appear to be endangered if the voltage stability calculation criterion is slightly decreased. An evident difference in the damping of the power oscillations was observed between the summer and winter operating conditions. The summer situations were observed to be more sensitive regarding power oscillations due to fewer generators equipped with power system stabilizers in operation compared with the winter situations. Especially, the impact of the largest generators on damping emerged in the research. The security margins were considerably smaller in the summer situations than in the winter situations when the damping ratios were used as calculation criteria. The currently used calculation criterion for power oscillations was observed to produce more consistent security margins compared with the examined damping ratio based criteria.

Keywords: transmission capacity, voltage stability, rotor angle stability, electromechanical oscillation, damping

The originality of this thesis has been checked using the Turnitin OriginalityCheck service.

TIIVISTELMÄ

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Pohjoismaisessa voimajärjestelmässä siirtokapasiteettia rajoittavia tekijöitä ovat jännite- ja kulmastabiilius sekä siirtojohtojen terminen kuormitettavuus. Mitoittavan vian jälkeinen jännitestabiilius rajoittaa Suomen voimajärjestelmän siirtokykyä tuotaessa tehoa Ruotsista Suomeen. Suomesta Ruotsiin tehoa vietäessä siirtokykyä rajoittava tekijä on alueiden välisten sähkömekaanisten heilahtelujen vaimentuminen. Heilahtelut näkyvät monissa eri voimajärjestelmän suureissa, mutta niihin viitataan usein tehoheilahteluina.

Siirtokapasiteettilaskennassa sovelletaan voimajärjestelmän käytön raja-arvoja laskentakriteereinä, jotka määrittävät sallitut käyttötilanteet. Tässä työssä tutkitaan jännitestabiiliudelle sekä tehoheilahtelujen vaimentumiselle asetettujen raja-arvojen valinnan vaikutusta Suomen voimajärjestelmän siirtokapasiteettiin sekä käyttövarmuusrajoihin. Siirtokapasiteettilaskennassa käytettäviä raja-arvoja tutkitaan erilaisissa käyttötilanteissa, ja tarkastellaan, miten siirtokapasiteetti ja käyttövarmuusrajat muuttuisivat eri raja-arvoja laskennassa käytettäessä. Tutkimusmenetelminä käytetään tehonjako- sekä dynamiikkalaskentaa. Lisäksi tehoheilahtelujen vaimentumista tutkitaan Pronyn menetelmällä.

Tutkimus osoitti, että jännitestabiiliuden raja-arvon pienentäminen kasvattaisi siirtokapasiteettia, mutta pienentäisi käyttövarmuusrajoja. Siirtokapasiteetin havaittiin vaihtelevan eri käyttötilanteissa merkittävästi. Toisaalta käyttötilanteiden välinen käyttövarmuusrajojen vaihtelu oli vähäisempää. Tutkittujen käyttötilanteiden perusteella Suomen voimajärjestelmän käyttövarmuus ei näytä vaarantuvan jännitestabiiliuden raja-arvoa maltillisesti pienennettäessä. Tehoheilahtelujen vaimentumisessa havaittiin selvä ero kesä- ja talvikäyttötilanteiden välillä. Kesätilanteiden havaittiin olevan herkempiä tehoheilahtelujen suhteen johtuen käytössä olevien lisästabilointipiirillä varustettujen generaattoreiden vähäisemmästä määrästä verrattuna talvitilanteisiin. Tutkimuksessa nousi esiin erityisesti suurimpien generaattoreiden vaikutus vaimennukseen. Käyttövarmuusrajat olivat kesätilanteissa huomattavasti pienempiä kuin talvitilanteissa vaimennuskertoimia laskennassa käytettäessä. Nykyisin käytössä olevan tehoheilahtelujen laskentakriteerin havaittiin tuottavan yhdenmukaisemmat käyttövarmuusrajat verrattuna tutkittuihin vaimennuskertoimiin perustuviin kriteereihin.

Avainsanat: siirtokapasiteetti, jännitestabiilius, roottorin kulmastabiilius, sähkömekaaninen heilahtelu, vaimennus

PREFACE

This master's thesis was made for the Finnish transmission system operator Fingrid Oyj between February and October 2019. I would like to thank my supervisor Marcin Pohjanpalo for the comments and advise. I would also like to present gratitude to all the members of the steering group of my thesis and other employees of Fingrid who have given me valuable advise during my work.

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Helsinki, 7.10.2019

Jani Stenroos

CONTENTS

ABBREVIATIONS AND SYMBOLS

AC	Alternating Current
CIGRE	International Council on Large Electric Systems (French: Conseil International des Grands Réseaux Électriques)
DC	Direct Current
DSA	Dynamic security assessment
ENTSO-E	European Network of Transmission System Operators for Electricity
FB	Flow Based method
FG1-FG5	Fault Groups
FRM	Flow Reliability Margin
HVDC	High Voltage Direct Current
IEEE	Institute of Electrical and Electronics Engineers
NTC	Net Transfer Capacity
N-1	Criterion for system security
OL3	The third unit at Olkiluoto nuclear power plant
PSS	Power System Stabilizer
PSS/E	Power System Simulator for Engineering
PTDF	Power Transfer Distribution Factor
P1	Transmission cut between northern and southern Finland
RAC	AC connection between Finland and Sweden
RAM	Remaining Available Margin
RDC	HVDC connection between Finland and Sweden
RSC	Regional Security Coordinator
SSA	Static Security Assessment
TRM	Transmission Reliability Margin
TSO	Transmission System Operator
TTC	Total Transfer Capacity

A	amplitude
A_0	initial amplitude
f	frequency
F_{max}	maximum flow
P	active power
t	time
T_D	damping torque coefficient
T_e	electrical torque
T_S	synchronizing torque coefficient
V	voltage

δ	rotor angle
ζ	damping ratio
τ	time constant of damping
ω	angular speed

1. INTRODUCTION

The growing volume of renewable energy resources in the power system combined with the increasing inter-country power transmission has made controlling and predicting of the usable transmission capacity more complicated. To ensure the efficient electricity market, the utilization of the power systems' transmission capacity is aimed to be maximized in the European Union.

A centralized calculation service provider of the Nordic transmission system operators, the Nordic Regional Security Coordinator, is launching its operations. The Nordic Regional Security Coordinator will produce some calculations formerly performed by the national transmission system operators, such as transmission capacity calculation. The varying calculation methods and criteria of the Nordic transmission system operators would be beneficial to harmonize as the Nordic Regional Security Coordinator begins to conduct the calculations. The goal of this thesis is to analyze how choosing the transmission capacity calculation criteria would affect the Finnish power system transmission capacity and security margins.

As demonstrated later in this thesis, the power import from Sweden to Finland is much more common than the export situations from Finland to Sweden at present. However, the increasing amount of wind power and the implementation of the new Olkiluoto nuclear power plant will affect the production-consumption balance and increase the energy self-sufficiency in Finland. Thus, the power export situations may become more common in the future.

The transmission capacity is restricted by the thermal limits of the grid components and power system stability. This thesis concentrates on examining the limits for voltage stability and damping of the electromechanical oscillations. In the Finnish power system, voltage stability is the transmission capacity limiting factor in the import situations and the damping of electromechanical oscillations in the export situations [1]. The thermal limits are not covered in this thesis.

The research is limited to the transmission capacity between northern and southern Finland. Part of the research question is how does choosing the limit for voltage stability would affect the computational transmission capacity of the Finnish power system. On the other hand, the impacts of applying various voltage limits on the voltage stability security margin are examined. Another main part of this thesis is to study the effects of choosing the limit for the damping of the electromechanical oscillations. Various damping ratios are applied in the research to examine how the transmission capacity and security margins of the Finnish power system are affected if the currently used damping criterion was changed.

The steady-state voltage stability is studied by means of load flow calculations and the post-fault transient behavior of the power system is examined by dynamic analysis. A signal processing technology called Prony analysis is utilized in examining the damping of the electromechanical oscillations in this thesis. The Prony analysis is derived from the output of the dynamic analysis.

The characteristics of the Nordic and Finnish power system are presented in Chapter 2. Chapter 3 gives the basics of the power system planning concentrating on the power system stability and security which represent the factors affecting the transmission capacity. Chapter 4 presents the methods of determining the transmission capacity and the capacity limiting factors in the Nordic power system. Furthermore, the concept of dynamic security assessment is explained in Chapter 5 along with the information about the methods and data used to carry out the research part of this thesis. The results of the research are presented in Chapter 6 and the findings are discussed in Chapter 7. Finally, the conclusions based on the findings are summarized in Chapter 8.

2. FINLAND AS PART OF NORDIC POWER SYSTEM

Finland is part of Nordic synchronous area. In other words, the Finnish power system is connected with Norway, Sweden and eastern Denmark and those countries together form a synchronized system where a common frequency exists. Western Denmark belongs to Continental European power system being connected with the Nordic system via high voltage direct current (HVDC) connections. Thus, Western Denmark is not part of the Nordic synchronous area.

The characteristics of the Nordic power system are discussed in Chapter 2.1. The Finnish transmission grid is described in Chapter 2.2 and the border connections between Finland and the neighboring countries are presented in Chapter 2.3. Chapter 2.4 describes the relevance of ENTSO-E in relation to this thesis.

2.1 Characteristics of the Nordic power system

The electricity generation resources differ widely between the Nordic countries. Norway mainly has hydro power, whereas wind power and thermal energy are dominating in Denmark. Finland and Sweden have the most mixed resources [2, p. 9].

With regard to the geographical location of the generation resources in the Nordic countries, hydro power is concentrated mainly in Norway but also in northern Sweden and Finland. Thermal power is located in Denmark and the southern parts of Finland and Sweden. Wind power is dominating in Denmark, particularly in western part of the country. [2, p. 9] However, the amount of wind power is increasing in other countries too. For example, according to Suomen Tuulivoimayhdistys, there are currently over 200 wind power projects (16500 MW) in the planning stage in Finland [3].

The yearly electricity consumption exceeds production in Finland. Thus, Finland is dependent on the electricity import from Sweden. Production exceeds consumption most of the hours of a year in Sweden and Norway whereas in Denmark there is a generation deficit half of the hours of a year. [4, pp. 14-17] The border connections between the Nordic countries are used to even out the differences in the regional consumption and production balance.

The Nordic countries are connected by alternating current (AC) and HVDC connections. There are also HVDC connections to countries outside the Nordic synchronous area. Interconnections between northern European countries are presented in Figure 2.1. The purple lines in Figure 2.1 are HVDC links and other colors represent AC transmission lines.

The interconnection of the individual countries' power systems into a larger system brings about significant benefits. A large synchronous area means improved security as the generation resources are dispersed geographically and the features of the resources vary between the subsystems. Thus, balancing power is available also during exceptional conditions, such as a shortage of fuel or a drought year which reduces the subsystems need for reserve power [2, p. 8]. The interconnected system also enables the common Nordic electricity market.

As can be seen in Figure 2.1, there are several interconnections connecting the Nordic system with the neighboring power systems. The HVDC links are connecting Norway to the Netherlands. Sweden is connected to Germany, Poland and Lithuania. Furthermore, Finland is connected to Estonia and Russia. There are also several HVDC links from Norway, Sweden and eastern Denmark to western Denmark. [5] A new HVDC link from Norway to Great Britain is currently under construction. When completed in 2021, it will be the longest subsea power cable in the world [6]. Another new HVDC link from Norway to Germany will be put into operation during 2019 [7]. The new HVDC links are also shown in Figure 2.1.

Figure 2.1. *Nordic transmission grid and interconnections outside the synchronous area. Purple lines are HVDC interconnections, red lines are 380–400 kV transmission lines, yellow lines are 300–330 kV transmission lines and green lines are 220–275 kV transmission lines [8].*

2.2 Finnish transmission grid

The Finnish transmission grid consists of the 400 kV, 220 kV and 110 kV transmission lines. Fingrid operates the whole 400 kV and 200 kV networks and about half of the 110 kV network in Finland. The other half of the 110 kV lines is owned by the regional or distribution network operators.

A map of the Finnish transmission grid is presented in Figure 2.2. The amount of 220 kV grid marked green in Figure 2.2 is decreasing as Fingrid replaces old technology and increases transmission capacity. For example, a new 400 kV connection from Oulu to

Petäjävesi called Forest Line is being planned and will be completed by 2022. The Forest Line will replace the 220 kV lines in central Finland. Thus, the 220 kV network will be obsoleted in southern area of Oulujoki by 2022. [9, pp. 27, 43]

The Finnish power system is connected to northern Sweden by two 400 kV AC lines (Petäjäskoski–Letsi and Pikkarala–Svartby). In addition, there is a weak 220 kV AC connection to Norway in northern Finland (Utsjoki–Varangerbotn). [10, pp. 62-63] The Finnish power system is also connected to southern Sweden by two HVDC interconnections, Fennoskan 1 and 2. Fennoskan 1 is located between Rauma and Dannebo and Fennoskan 2 between Rauma and Finnböle [11]. A third AC connection between Finland and Sweden is currently being planned with the completion scheduled in 2025. Similarly to the current AC lines between Finland and Sweden, the third AC connection will also be located in northern Finland. [9, p. 27]

Interconnections from Finland outside the Nordic synchronous area include HVDC links Estlink 1 and 2 which connect the Finnish system to Estonia. Estlink connections can be seen as brown lines in southern Finland in Figure 2.2. There are also three 400 kV AC transmission lines between Finland and Vyborg, Russia [12, p. 16]. However, two of the Russian connections are not synchronous but direct current (DC) is used to separate the two asynchronous systems. A back–to–back AC–DC–AC conversion is implemented in Vyborg meaning that the rectifiers and inverters are located in the same substation and the substation is connected to the Finnish and Russian power systems by AC lines. The third 400 kV AC line is used to synchronize a power plant called the North West Power Plant near St. Petersburg to the Finnish power system. [13, p. 30] Therefore, there are no synchronous interconnections between Finnish and Russian power grids.

In addition, there are 110 kV transmission lines from Imatra and Ivalo to Russia. Those lines can be used to connect hydro power plants located on the Russian side of the border to the Finnish power system [5]. However, the 110 kV connections between Finland and Russia are not owned by Fingrid. [13, p. 29] There is also a low capacity HVDC link from Naantali to Åland owned by Ålands transmission system operator Kraftnät Åland [5].

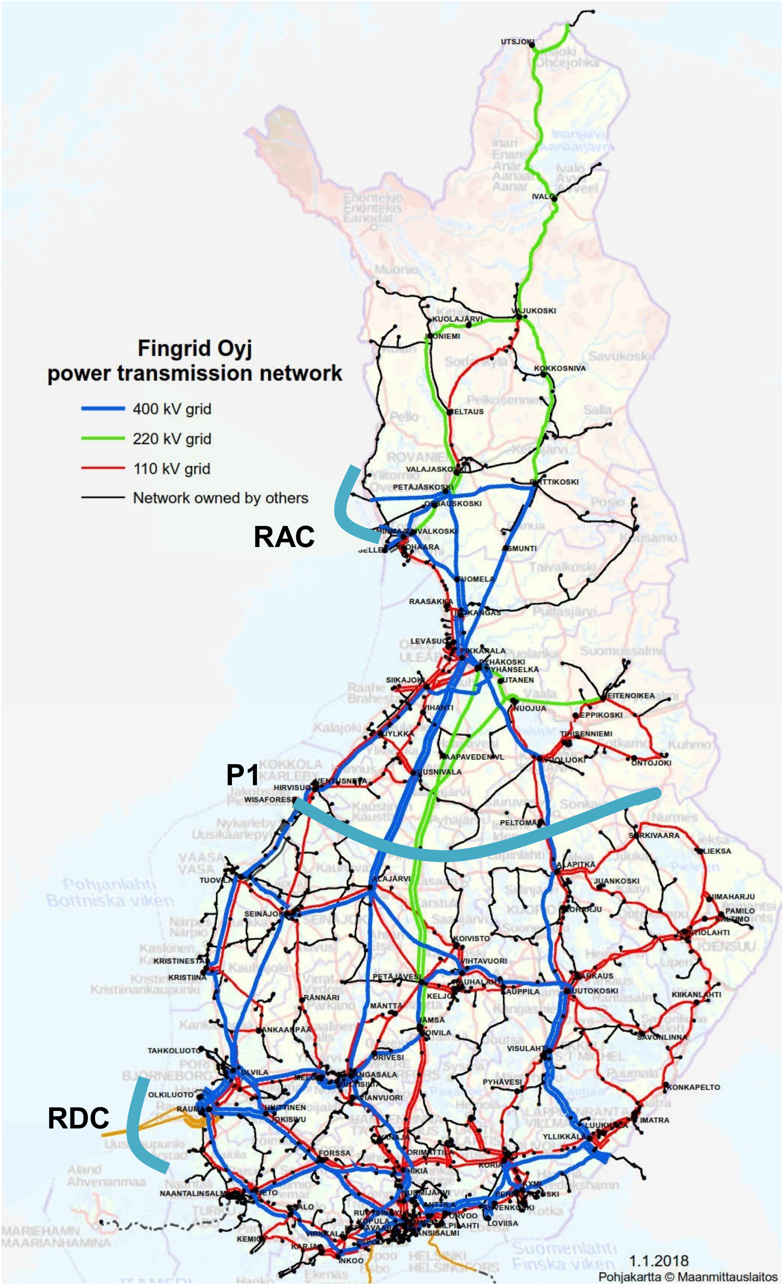

Figure 2.2*. Finnish transmission grid and the main transmission cuts. Modified from [14].*

There are a few cross-sections in the Finnish transmission grid which may cause physical limitations for transmission capacity. A Cross-section means a bottleneck which impacts on the transmission capacity need to be studied. A term transmission cut is also used to refer to the bottlenecks in the grid. The most common cross-sections to be studied in the Finnish transmission grid are presented in Figure 2.2 and they are called cut P1, RAC cut and RDC cut [2, p. 10]. Cut P1 is an internal cross-section located in the middle of Finland. It is running from Pietarsaari via north of Iisalmi to the east. Cut P1 consists of four 400 kV and two 220 kV transmission lines running in the north-south direction. In the future, the north-south directional power transmission in cut P1 will increase as new generation such as a substantial part of wind power and the Hanhikivi 1 nuclear power plant will be located in northern Finland [9, pp. 21-22].

The other two transmission cuts include the cross-border interconnections from the Finnish system to Sweden. The RAC cut is located in Lapland and it consists of two 400 kV AC lines. The third AC connection to Sweden will increase the transmission capacity between Finland and Sweden nearly 30 per cent in 2025 [9, p. 30]. The RDC cut includes the Fennoskan HVDC links from southern Finland to Sweden as can be seen in Figure 2.2. In addition to the cross-sections described above, additional cross-sections may be formed while needed.

2.3 Finnish interconnections with neighboring countries

The maximum commercial transmission capacities of the Finnish interconnections are presented in Table 2.1. The capacities are determined by a Net Transfer Capacity (NTC) method which is discussed in Chapter 4.1.

Table 2.1 *Maximum net transfer capacities of the Finnish interconnections [12].*

Interconnection	To Finland (MW)	From Finland (MW)
RAC	1500	1100
Fennoskan 1 & 2	1200	1200
Estlink 1 & 2	1016	1016
Russia	1300	320

As can be seen in Table 2.1, the transmission capacities of the HVDC connections Fennoskan and Estlink are the same for import and export. The Fennoskan 1 cable was damaged in 2013 and it is currently operated at reduced voltage [15]. Thus, the commercial transmission capacity of Fennoskan 1 is nowadays 400 MW instead of the nominal maximum capacity of 500 MW. The transmission capacity of Fennoskan 2 is 800 MW. For Estlink 1, the transmission capacity is 350 MW in summer and a 15 MW temperature dependent overload capacity can be utilized during winter. The capacity of Estlink 2 is 650 MW. The additional 16 MW capacity of the Estlink connections in Table 2.1 is due to loss power purchasing arrangements. [12]

The AC interconnection between Finland and Sweden (RAC) has a 1500 MW capacity from Sweden to Finland and 1100 MW capacity from Finland to Sweden. The difference between RAC capacities is due to stability and reliability issues discussed more closely in Chapter 4.3. There is no commercially available transmission capacity between

Finland and Norway due to the weak connection. Instead, Finland–Norway capacity is taken into account in RAC capacity and it may affect that up to 120 MW [12, p. 16].

As described in Table 2.1, the transmission capacity from Russia to Finland is 1300 MW and from Finland to Russia 320 MW. The import and export capacities differ as the back–to–back converter station was originally built for one-way power flow from Russia to Finland only [13, p. 30]. Since 2014, one of the four converter units has also been able to export power from Finland to Russia. [16, p. 48]

2.4 ENTSO-E

The European Network of Transmission System Operators for Electricity (ENTSO-E) is an organization of 43 European Transmission system operators (TSO). ENTSO-E's role is to promote the internal electricity market and transmission system development in EU. ENTSO-E's legally mandated tasks include:

- Ensuring the secure and reliable operation of the European transmission network
- Advancing cross-border interconnection development and integration of renewable energy resources
- Enhancing the creation of the internal electricity market

To achieve these tasks, ENTSO-E involves in network development and publishes network codes, the common codes of conduct for TSOs, producers and traders. [17]

According to ENTSO-E, the national TSO's are facing challenges to forecast and manage the short-term changes in power flows themselves as the cross-border electricity exchange and the amount of renewable energy resources in the network are increasing [18, p. 5]. To solve that problem, ENTSO-E proposed establishing the Regional Security Coordination Initiatives which have five core services:

- operational planning security analysis
- coordinated capacity calculation
- outage planning coordination
- short- and medium-term adequacy forecasts
- individual and common grid model delivery

These services produce calculations and other information which can be utilized by the TSOs for decision-making. [18]

The Nordic Regional Security Coordinator (Nordic RSC) was established in 2016 [19]. It will offer the formerly presented five services for the Nordic TSOs. The coordinated capacity calculation service is the most relevant regarding this thesis. Currently, all Nordic TSOs are using their own criteria for transmission capacity calculation. As the Nordic RSC will begin to perform the capacity calculation, it would be beneficial if the calculation criteria could be harmonized. The goal of this thesis is to analyze how choosing the calculation criteria would affect the Finnish power system security margins and transmission capacity.

3. POWER SYSTEM PLANNING

The basic principles of power system planning are defined in Nordic grid code [2], a document for Nordic TSOs aiming to harmonize and coordinate the Nordic grid planning and operation. The Nordic Grid Code consists of the Planning Code, Connection Code, Operational Code, and Data Exchange Code. The last two are binding agreements among the Nordic TSOs whereas the Planning Code and the Connection Code are recommendations which should be followed. The Nordic grid code was published by Nordel, an association of the Nordic TSOs, which was disbanded in 2009 and the tasks of Nordel were transferred to ENTSO-E [20]. The European-wide grid planning and operation is at present guided by the network codes published by ENTSO-E

The power system planning can be divided into long- and short-term planning. Short-term planning includes the grid building plans for about five years whereas long-term planning includes the general grid plan and the guideline for the grid development for 5-15 years. Long-term power system planning also includes reliability of the system. Reliability consists of system security and system adequacy. System security refers to the ability of the power system to withstand disturbances such as the short circuit faults and disconnection of components. System adequacy means there is sufficient amount of generation and transfer capacity to meet demand. Reliability may be assessed by indexes covering the average fault frequencies and -durations. [10, pp. 276-277]

The goal of power system planning is to ensure a secure and reliable infrastructure to connect the electricity generation and consumption. The grid investments must be economical and based on the reasonable needs of the users meaning that unnecessary investments are not allowed. In addition, the system security must be at such level that the ordinary faults are not causing interruptions. [10, p. 73] The electricity market law obligates Fingrid to publish a ten-year main grid development plan. The development plan is updated every second year, and it contains the description of the investments being planned to meet the grid development responsibilities. [9, p. 3]

Power system planning is based on the calculations and simulations. Power flows in different network states are studied by load flow analysis. Power flows change depending on the season and the switching state of the system. Short circuit currents are calculated to configure the protection devices such as relays. The dynamic stability of the system is assessed by dynamic analysis which means simulating transient events such as network faults and studying if they cause instability or does the system remain stable after the faults. [10, p. 76] In this chapter, a term power system stability is defined and the categories of stability are explained. Another aspect of power system planning, security, is also discussed in this chapter.

3.1 Stability

Power system stability means the capability of the system to maintain steady operation despite the faults and changes in the operation condition. The Institute of Electrical and Electronics Engineers (IEEE) and International Council on Large Electric Systems (CIGRE) defined stability in their report as follows: “Power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact.” [21] Stability is a feature of the whole system. The power system may maintain stability despite a single generator losing stability and disconnecting from the grid. In addition to generators remaining synchronous, voltage levels and frequency must be in an acceptable level in a stable power system. [10, p. 216]

A schematic illustration of power system stability is presented in Figure 3.1. Power system stability is divided into three main categories: rotor angle stability, frequency stability and voltage stability. The main stability categories in Figure 3.1 are further divided into sub-categories based on the magnitude and duration of the phenomenon being examined. The rotor angle- and voltage stability are discussed in the following chapters.

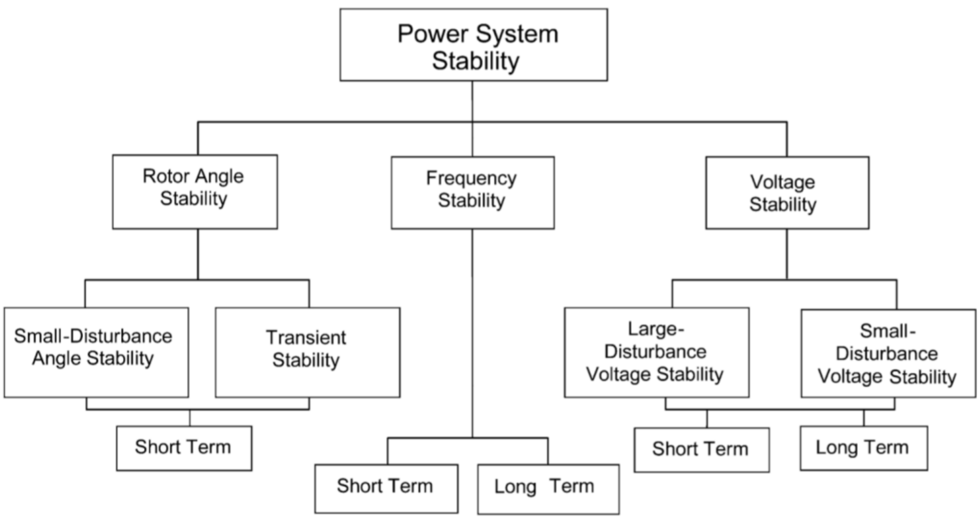

Figure 3.1. *Illustration of the power system stability classification [21].*

3.1.1 Voltage stability

Voltage stability means the ability of a power system to maintain voltages at allowed level in normal operation and after a disturbance. Voltage instability means that voltage drops progressively in some bus in the power system. Voltage instability may lead to voltage collapse if the instability spreads and leads to a low-voltage profile in a larger part of the power system. Voltage stability and voltage drop are also associated with rotor angle stability. [22, p. 27]

As can be seen in Figure 3.1, voltage stability is divided into large-disturbance and small-disturbance stability. Large-disturbance voltage stability stands for the ability of the power system to maintain steady voltages after large disturbances such as short-circuit faults or loss of generation. Small-disturbance voltage stability means the power system ability to maintain steady voltages after minor changes in the system such as changes in the load and generation. The main reason for voltage instability is the inability of the power system to meet the reactive power demand. [10, p. 246], [22, p. 32]

Another method of classifying voltage stability is based on the duration of the phenomena being explored. For short-term voltage stability, the time frame is several seconds and the analysis concerns dynamics of fast acting components such as HVDC converters. While exploring long-term voltage stability, the scope is in slower acting power system components. The time frame for long-term voltage stability is several minutes and the components of interest are for example tap-changing transformers and automatic generator control. [21, p. 1392] Long-term voltage stability analysis assumes the damping of power oscillations and a constant frequency in the power system [22, p. 33].

Voltage stability analysis involves the following aspects: proximity to the voltage instability and mechanism of voltage instability. Proximity to instability can be measured for example in terms of active power flow through a critical transmission cut or load level. Mechanism of instability answers to questions such as how the instability occurs and what is the origin of instability. [22, p. 977]

P-V curve or “nose curve” of voltage stability can be drawn to illustrate the behavior of voltages as a function of transferred power. Figure 3.2 presents voltage in the receiving end of a transmission line in a function of power transferred in the line and a few $\tan\varphi$ values. $\mathrm{Tan}\varphi$ represents a relation between reactive and active power in the receiving end of the transmission line. [10, p. 252] A constant power load is assumed in Figure 3.2.

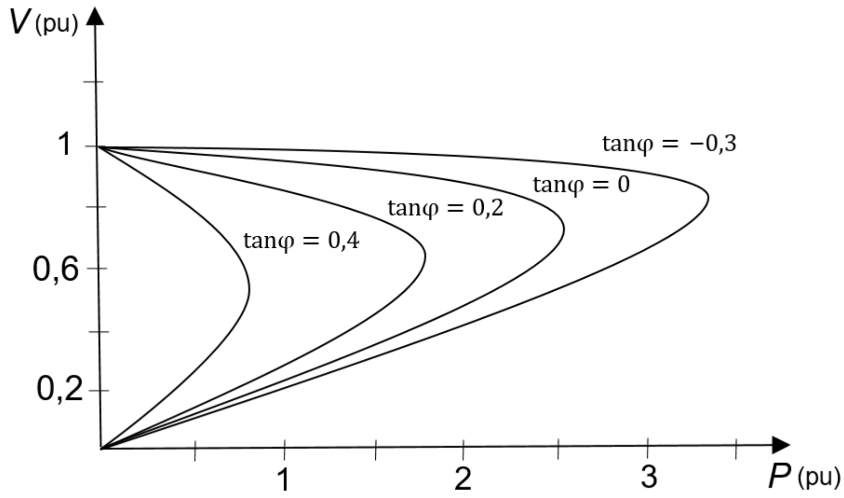

***Figure 3.2**. P-V curve. The receiving end voltage of the transmission line presented as a function of the power transmission and a few different tanφ values.*

For a given value of active power (*P*), two values of voltage (*V*) exist in the P-V curve. The nose point in P-V curve is the critical point, a maximum value of active power that can be transferred as the power system remains stable. If the power transmission increases to the nose point, voltage collapse may occur and the system may lose stability. Thus, only the upper operating points are acceptable. In practice, the power system can not be operated in the point of maximum power, but a security margin is used to ensure a stable operation also during occasional changes in the system such as the disconnection of a power system component or some other fault.

Voltage instability may cause the loss of load and tripping of transmission lines or other power system components which induces outages and may spread the initially local instability problem. HVDC links are also part of the voltage instability problem. Instability is typically related to the reactive power control of the converter stations and voltage instability of HVDC links is normally associated with the links connected to weak AC lines. [21, p. 1391]

In addition to the usual cause of voltage instability, a progressive voltage drop, voltage rise can also cause instability. That has been demonstrated in Montreal where load tripping caused the transformers on-load tap changers to attempt to raise the voltages and restore the load power which led to voltage instability. [23, pp. 286-287]

3.1.2 Rotor angle stability

Rotor angle stability means the synchronous generators' ability to maintain synchronism [22, p. 18]. To retain synchronism, the generators in a synchronous power system must be able to return the balance between mechanical and electrical power after disturbances in the power system. When the balance between the electrical and mechanical power changes, the angular difference between the grid voltage and the electromotive force inside the generator also changes. Thus, a new operating point of the generator in $P(\delta)$ curve is defined by the new angular difference δ and the electrical power P. [10, pp. 218, 222]

A $P(\delta)$ curve is presented in Figure 3.3. As can be seen in Figure 3.3, the electrical power of a generator is increasing as the angular difference increases. The maximum power is achieved when the angular difference is 90 degrees [22, p. 20]. In steady-state, the angle of 90 degrees also defines if the generator is stable or not. If the angle increases to over 90 degrees, the generator loses stability. [10, p. 221]

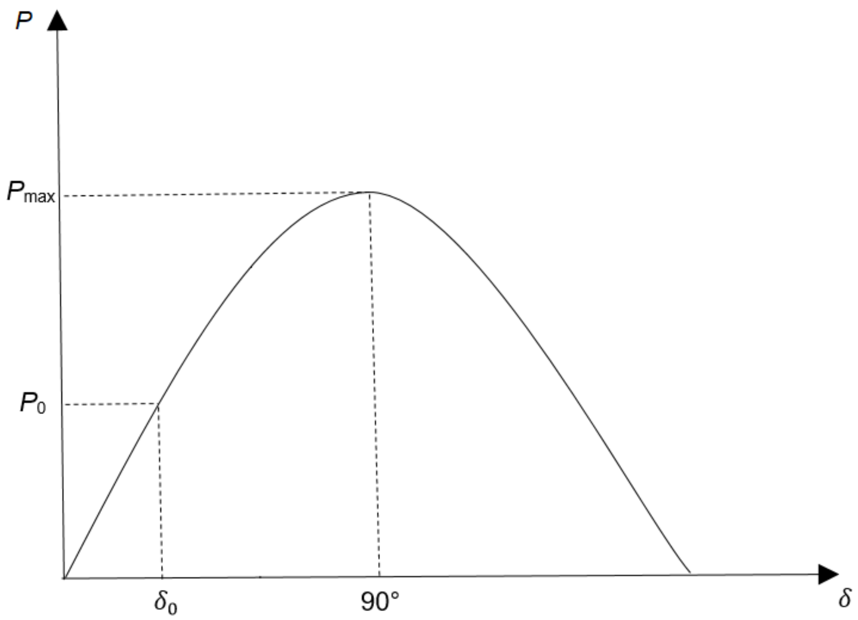

Figure 3.3. The $P(\delta)$ curve of a generator. 90 degrees is the rotor angle stability limit in steady-state.

During short-term transient events, such as network faults, the angle difference can exceed 90° and the situation may still remain stable. However, the fault must be cleared sufficiently quick to prevent the generator accelerating too much due to decreased electrical power during the fault. [10, pp. 230-233]

The change in the electrical torque of a synchronous machine ΔT_e after a fault can be divided into synchronizing torque component $T_S \Delta\delta$ and damping torque component $T_D \Delta\omega$. The relations between these torque components can be presented as:

$$\Delta T_e = T_S \Delta\delta + T_D \Delta\omega \tag{3.1}$$

Where T_S is the synchronizing torque coefficient, $\Delta\delta$ is the rotor angle shift, T_D is the damping torque coefficient and $\Delta\omega$ is the angular speed deviation [22, p. 23]. In order for the generator retaining stability, both of the torque components must be at a sufficient level. If a synchronous generator loses stability, it must be disconnected from the grid in order for the other generators being able to continue stable operation [10, p. 218].

As can be seen in Figure 3.1, rotor angle stability is divided into two sub-categories: small-disturbance angle stability (or steady-state stability) and transient stability. Small-disturbance stability means the power system ability to maintain stability in small disturbances, such as changes in load and generation. The forms of instability that may occur are [22, p. 23]:

1. Continuous increase of the rotor angle due to insufficient synchronizing torque (Figure 3.4 b)
2. Rotor angle oscillations of increasing amplitude due to insufficient damping torque (Figure 3.4 c)

The second form of instability, oscillation of increasing amplitude, is more common [24].

Transient stability means the power system ability to retain synchronism after a serious transient disturbance such as a short circuit fault. The resulting forms of instability are the same as above. The form of instability caused by insufficient synchronizing torque is called the first-swing instability. However, transient instability may not necessarily occur at the first swing, but in large power systems the rotor angle may make large excursions after the first swing too. [22, pp. 25-26] In transient stability studies, the dynamic behavior of the power system is usually simulated approximately 20 seconds after the beginning of the studied fault [10, p. 228].

The consequences of the relations between the torque components are illustrated in Figure 3.4. In Figure 3.4 a) both the synchronizing and damping torque components are at sufficient level and the oscillation dampens. In Figure 3.4 b) the synchronizing torque component is insufficient which leads to the continuous increase of the rotor angle and in Figure 3.4 c) the damping torque component is insufficient leading to the oscillation of increasing amplitude.

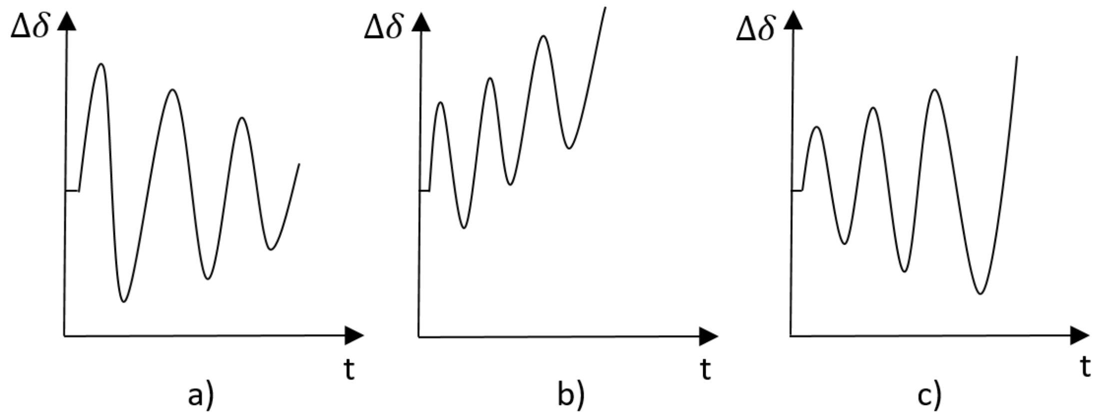

***Figure 3.4. a)** Damping oscillation, stability remains **b)** continuously increasing rotor angle, instability due to insufficient synchronizing torque **c)** the rotor angle oscillation of increasing amplitude, instability due to insufficient damping torque.*

The electromechanical oscillations caused by the insufficient damping torque can be observed in many quantities such as power flows, generator speeds and voltage magnitudes. The damping of the oscillations is the power transmission limiting factor during high power flow from a small power system to a larger one. [25] The oscillations must be able to damped out to prevent them causing instability.

The electromechanical oscillation modes can be classified into the local modes, inter-area modes, control modes and torsional modes. The local modes appear in frequencies from 0.7 to 2 Hz and they are associated with a single generator or a power plant oscillating against the rest of the system. The inter-area modes are present while many generators in one part of the power system oscillate against the generators in other parts of the system. The frequency range of the inter-area mode is from 0.1 to 0.7 Hz. The control modes are associated with the generator control systems and torsional modes are caused by the turbine-generator shaft systems interacting with the control systems. [22, pp. 25, 817-818]

3.2 Security and N-1 criterion

The transmission grid security of supply must be at the high level. Therefore, meshed structure is used in transmission grid design to ensure an alternative route for power flow in case some grid component gets faulted or there is a planned outage in the grid. Unlike in the radial distribution grid, a fault in the meshed transmission grid does not cause an outage. [10, p. 271] For example, the transmission reliability of Fingrid was 99.9999 percent of the transferred energy in 2018 [26].

An N-1 criterion is applied in the transmission grid design and operation. The N-1 criterion means that the power system must withstand the loss of any single component such as the power line, transformer, generation unit or bus bar. The fault which has the largest impact on the power system is called a dimensioning fault. The dimensioning fault is usually the disconnection of the largest production unit in the system. Another possible dimensioning faults in the Finnish system may be faults in the substations and the inter-area lines. [2, p. 67]

According to the Nordic Grid Code, a dimensioning fault in a subsystem, such as the Finnish power system, is not allowed to cause serious disturbances in other subsystems in the Nordic synchronous area [2, p. 67]. The maximum transmission capacity of the transmission grid is restricted by the dimensioning fault. One consequence of the N-1 criterion is that the transmission capacity of the system is not the sum of the capacities of the individual lines. If one transmission line is disconnected, the remaining lines must be able to transfer the power flow of the disconnected line. [10, p. 279]

The operational states of the power system are defined in the Nordic grid code. In the *normal state,* the frequency, voltage and power transmission are within the acceptable limits, consumption requirements are being met and reserve requirements are fulfilled. The power system is prepared to handle a dimensioning fault in the normal state. In the *alert state* the reserve requirements are not fulfilled and faults in the grid components or generation disconnection will lead to the *disturbed state* or the *emergency state.* [2, p. 59] According to the Nordic grid code, the power system must be restored to normal state within 15 minutes after a disturbance [2, p. 67]. In other words, after a fault, the power system must be in 15 minutes in a state it withstands a dimensioning fault again.

The *disturbed state* means that the frequency, voltage and power transmission are not at the acceptable level, and it is not possible to restore the power system to the normal state in 15 minutes. In the *emergency state*, the compulsory load shedding has been applied. Production disconnection may occur and the network may split into islands. In addition, the fifth operation state, *network collapse*, has been defined. It means that all loads in one or more areas are shed and production disconnection and islanding can occur. [2, p. 62]

In the security criteria, acceptable consequences are determined for various combinations of operating situations and faults. More severe consequences can be allowed for the less common faults. In the Nordic grid code, the faults are divided into groups FG1-FG5 with regard to their prevalence. The FG1 and FG2 faults are the most frequent single faults such as the loss of a generation unit or a transmission line. The FG3 faults are less frequent single faults and the more common double faults. The groups FG4 and FG5 consist of rare faults like the combinations of simultaneous faults. The faults in FG1-FG3 are N-1 faults, i.e. they are considered as dimensioning faults. [2, pp. 23-27]

The assessment of power system security is done by dynamic and steady-state analysis. Security during a disturbance is assessed by dynamic simulations, which examine if the system remains stable or is the disturbance causing the system to collapse. The voltage levels and power flows are examined in steady-state analysis, which means load-flow calculations after the post-fault oscillations have damped. [10, p. 280]

The security of a power system depends on the operation mode, i.e. the same fault may cause different consequences depending on the switching and transmission state of the system. Other factors influencing the power system operation mode are the load flow, amount and location of loads and generation and the types of generators connected to the grid. [10, p. 280] For example, the nuclear units' yearly revisions are typically taking place in summer whereas in winter their large synchronous generators are in full operation and able to contribute to power system control and operation. On the other hand, the largest river flows are usually in the spring due to floods. Thus, the peak in hydropower production usually takes place in the spring. Furthermore, the combined heat and power production is at its peak in winter due to the increased heat power demand.

4. DETERMINING THE TRANSMISSION CAPACITY

This chapter defines a term transmission capacity and explains the transmission capacity limitations of the AC transmission systems. Practices of determining the transmission capacity in Nordic countries are also described in this chapter.

There are many subterms related to the term transmission capacity discussed later in this chapter but in general transmission capacity means the maximum power flow that the power system is able to transfer while the security criteria are conformed. Transmission capacity can be reviewed in terms of a single line, transmission cut or subsystem.

Currently, Net Transfer Capacity (NTC) method is used by Fingrid to calculate cross-zonal transmission capacities. However, according to The Guideline on Capacity Allocation and Congestion Management by ENTSO-E, so called Flow-Based (FB) approach should be used as the primary capacity calculation method [27]. The capacity calculation methods are explained in chapters 4.1 and 4.2.

4.1 Net Transfer Capacity

The Net Transfer Capacity (NTC) method is based on calculating the Total Transfer Capacity (TTC) first. The TTC represents the maximum amount of active power that can be transferred through a chosen boundary while the power system security criteria are taken into account. [12] A term grid transfer capability is also used by some sources [28, pp. 22-23]. The TTC is a technical maximum transmission capacity which is limited by the reliability and security criteria described in Chapter 3. The TTC is dependent on the state of the power system, such as which generators are in operation, the amount of load and generation, or possible power line outages in the system.

Part of the TTC is reserved for Transmission Reliability Margin (TRM). The TRM is a security margin which covers the TTC calculation errors and inaccuracies. The TRM takes into account the following sources of uncertainty: [1]

- Variations in power flows caused by automatically activated reserves
- Variations in power flows due to unanticipated variations in electricity consumption and production

- Inaccuracies in measurements and data collection

The TRM values are different for each connection, and they are defined based on the TSO experts' estimations. For example, the TRM for AC connection between Finland and Sweden is 100 MW. For DC connections, the TRM is 0 MW. [12]

When the TRM is subtracted from the TTC, the remaining capacity is called Net Transfer Capacity (NTC). The NTC is the commercial capacity offered to the electricity market. [12] In the market point of view, the NTC is the maximum power flow between two bidding zones when the technical limits and requirements of TSOs have been taken into account [28]. The relations between previously explained transmission capacity terms can be presented as:

$$\mathrm{NTC} = \mathrm{TTC} - \mathrm{TRM} \tag{4.1}$$

The factors defining TTC are explained in Chapter 4.4.

4.2 Flow-based method

The physical limits of the power system transmission capacity affect the price formation in the electricity market. To more accurately define the physical limits and inter-area power flows, a Flow Based capacity calculation method has been introduced. The current Nordic NTC method simplifies the transmission situation as it does not take into account that there is often more than one route for the power flow. For example, if power transmission between two areas increases, increased power flow in only one interconnection is assumed by the NTC method whereas in the FB method the increased power flow is divided into all the inter-area connections as in reality happens. [29, pp. 24-25]

The previously explained drawback of the NTC method concerns especially the systems which include several inter-area connections. In the Nordic system, there are several cross-border AC interconnections between Sweden and Norway. However, the AC connections between Finland and other Nordic countries are limited to the RAC cut. Therefore, the NTC method represents the cross-border power flow quite well in Finland but the implementation of the FB method may be necessary to constitute a common Nordic capacity calculation method.

In the FB method, the market capacity is limited by two factors, Power Transfer Distribution Factors (PTDF) and Remaining Available Margins (RAM). RAMs represent the capacity allocated to the electricity market in megawatts. The PTDFs illustrate how much power flow is increased in the inter-area connections by one megawatt increase in generation in a specific area. [29, pp. 26-28] In other words, the PTDFs represent how the power flows caused by changing generation or load are distributed in the transmission grid. Thus, the actual power flows can be better represented in the FB method than in the NTC method which may lead to better utilization of the transmission capacity and avoid unnecessary capacity limitations.

In the FB method, the term maximum flow F_{max} corresponds to the TTC in the NTC method. F_{max} is the maximum power flow taking into account the technical limits of the power system. Similarly, Flow Reliability Margin (FRM) as a term corresponds to the TRM in the NTC method. The RAM is calculated from the sum of the technical margins. [29, p. 45] The PTDFs and RAMs jointly form a set of parameters which describe the available transmission capacity between areas or bidding zones. [29, p. 42]

4.3 Transmission capacity limitations

In addition to N-1 criteria, the transmission capacity is limited by thermal- voltage- and rotor angle stability limitations. The thermal limitations mean the maximum current the transmission lines can conduct without violating safety rules or damaging the grid components. [12, p. 7] The higher current, the more the temperatures of the lines rise. High temperature causes the thermal expansion of the conductors which, for example, increases the sag of the transmission lines and may cause the lines to hang dangerously low. The transmission capacity of a short line is usually restricted by thermal limitations [10, p. 220]. The transmission capacity of the HVDC links is also restricted by thermal limitations but the effect of the HVDC link disconnection on the power system stability must be taken into account too [10, pp. 297-298]. The disconnection of an HVDC link may be a dimensioning fault in some conditions.

Voltage stability or rotor angle stability are usually the limiting factors regarding power transmission in the Nordic power system due to long transmission distances and high reactances in the grid. Thus, the transmission capacity between the Nordic countries is generally lower than what is the grid components' thermal capacity. Furthermore, the transmission capacity of some interconnections varies depending on the direction of the power flow or time of the year. [2, p. 9]

Voltage limitations mean that voltages must be within the defined minimum and maximum limits. The aim of the maximum voltage limit is to prevent damaging or premature aging of grid components due to high voltage. The minimum voltage limit is set to prevent the individual faults from causing a collapse of the interconnected system voltage which could lead to a blackout of the whole system. [12, p. 7]

Both steady-state voltage stability and transient voltage stability must be studied to determine the transmission capacity. Steady-state voltage stability means that voltages must be within allowed limits after the immediate post-fault oscillations have damped. Transient voltage stability means that the momentary voltage is not allowed to drop below a predefined limit during post-fault power oscillations. Voltage stability has been traditionally considered as a transmission capacity limiting factor in network areas where only a few or not any synchronous generators exist and power is transferred to the area from elsewhere. The reason for that is the dependency between voltage and reactive power. The less there are reactive power supplying resources in a specific area, the easier voltage stability may be lost after the disturbances. [10, p. 246]

Rotor angle stability limitations are associated with the requirement of the power system to withstand transient events also after a disturbance. The post-fault rotor angle oscillations of the synchronous generators cause power-, voltage-, and frequency oscillations in the power system. The synchronous generators’ oscillations with respect to one another must be damped after a disturbance to return the system to a stable operating point. If the stable operation can not be quickly returned, synchronization between generators may be lost and the whole interconnected power system may become unstable which could lead to a blackout. [12, p. 8]

When power is exported from Finland to Sweden, i.e. power flows through cut P1 from southern Finland to northern Finland and onward towards southern Sweden through RAC cut, the transmission capacity is restricted by post-fault power oscillation requirements [1]. This is illustrated in the upper left corner of Figure 4.1. The oscillations must be damped in an adequate time frame in order for the system retaining stability. The insufficient damping of the inter-area oscillations is the limiting factor especially as the power surplus is located in southern Finland and power is transferred to southern parts of Sweden and Norway, the transmission distance being about 2000 kilometers [30].

When power is imported from Sweden to Finland, i.e. power flows through RAC cut from Sweden to Finland and onward to southern Finland through cut P1, the transmission capacity is restricted by voltage limitations and the permissible loading of the transmission lines [1]. That is illustrated in the down right corner of Figure 4.1. The dimensioning fault during import situation is the disconnection of the largest generation unit in the Finnish system. The larger the disconnected unit is, the greater oscillations are caused by the disconnection and the transmission capacity is limited by transient voltage stability. If the disconnected generation unit is small, the transmission capacity is mainly limited by steady-state voltage stability as only minor voltage dips associated with power oscillations are resulting from the disconnection. [31, p. 176]

The damping issues during the north to south directional power flow were managed in the 1960s by building new power lines, equipping generators with the power system stabilizers and installing series compensators on long power lines. [32, p. 7] Thus, the damping of the power oscillations is usually not the transmission capacity limiting factor when power flows from Sweden to Finland as the power surplus is located in northern Sweden and the transmission distance to southern Finland is in that case about 1000 kilometers [30].

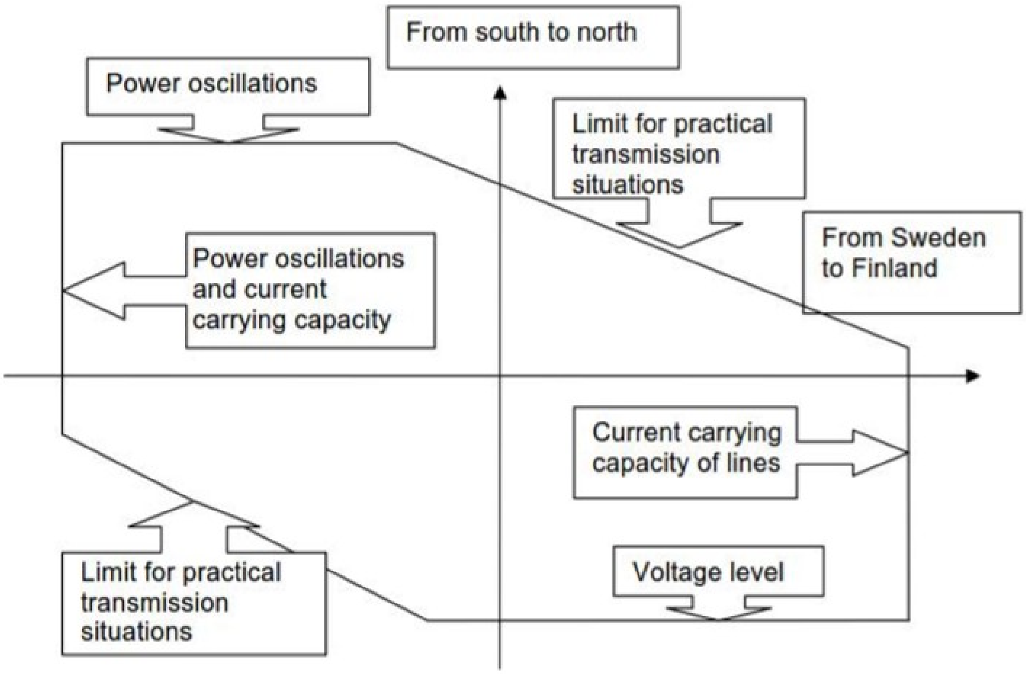

Figure 4.1. *The Finnish power system operating range diagram [1].*

The horizontal and vertical lines in Figure 4.1 illustrate the defined transmission capacities. The diagonal lines are limits which are not normally exceeded, even though the transmission capacity would allow it. In order to get to the upper right corner, i.e. high import from Sweden to Finland and simultaneously a huge P1 transmission from south to north, the major part of the load should be located in northern Finland. On the other hand, there should be lots of generation in northern Finland to cross the down left diagonal limit. In practice, exceeding the diagonal limits is not possible in normal operation considering the geographical distribution of the loads and generation in Finland.

4.4 Criteria for transmission capacity calculation

There are three factors studied by load flow calculations and dynamic simulations while determining the transmission capacity in the Nordic countries. The thermal limitations or loadability of the grid components is the first one but as stated in Chapter 4.3, rotor angle- and voltage stability are usually the more limiting factors in the Nordic power system. Therefore, this thesis is concentrated on studying the voltage stability and power oscillation damping criteria.

The damping of the oscillation amplitude can be presented as:

$$A = A_0 \mathrm{e}^{-t/\tau} \sin(2\pi f t) \tag{4.2}$$

where A is the oscillation amplitude, A_0 is the initial amplitude, t is time, τ is the time constant of damping and f is the oscillation frequency. The power oscillation of only one frequency is assumed in equation 4.2 to simplify the calculation. In reality, power oscillation is a combination of different frequencies which have different damping ratios. In the Nordic power system, the 0.3 Hz inter-area oscillation is dominating and simultaneously it is the worst regarding damping. [31, p. 176] During the 0.3 Hz oscillation, the generators in southern Finland oscillate against the generators in southern Sweden and Norway. The 0.3 Hz oscillation mode is usually present when power is transferred from southern Finland through P1 and RAC cuts to southern Sweden. Another main oscillation mode in the Nordic system is 0.5 Hz which occurs also when power is exported from Finland to Sweden. The 0.5 Hz oscillation is observable especially in Norway and Sweden. [33]

Concerning the power oscillations, there are three common methods of assessing damping. The first method of defining a damping criterion is to set an upper limit for the time constant of damping τ. Another method is to set a lower limit for the damping ratio ζ which can be presented as:

$$\zeta = \frac{1}{2\pi f \tau}. \tag{4.3}$$

Where f is frequency and τ is the time constant of damping. The third method of defining the damping criterion is to set a lower limit for the decreasing of the oscillation amplitude in a certain time. [31, p. 177] That is illustrated in Figure 4.2 which presents the decreasing of the oscillation amplitude in about five swing periods. The situation in Figure 4.2 is considered stable if after 20 seconds the oscillation amplitude has decreased to under 90 % of the first swing amplitude.

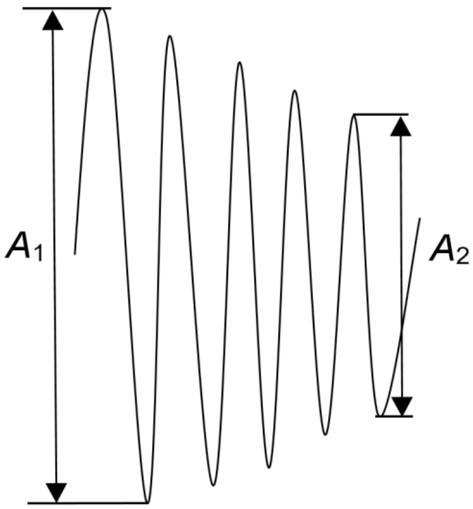

Figure 4.2. *Damping criterion used by Fingrid. Power oscillation must be damped at least 10 % in 20 seconds.*

According to Ruhle, a damping ratio lower than 3 % is usually considered as too weak damping whereas at least 5 % damping ratio is adequate. However, the minimum acceptable level for damping can not be unambiguously defined. [34] The adequate damping is system-specific. The stability assessment of Finnish transmission grid was studied in [35]. In the study, 3-5 % was considered as reasonable damping and 3 % damping was defined as a security criterion.

The basic principle of assessing the voltage stability is to find out if the studied operating condition is acceptable in relation to the P-V curve presented in Chapter 3.1.1. In addition, a security margin is needed to ensure that voltage stability remains after the contingencies too. Different methods of defining the voltage stability criteria are used but in general all of them are aiming to keep a certain margin from the nose point of the P-V curve in all operation conditions. Different variables such as total load in an area, power transfer through a certain crosscut, reactive power reserves or bus voltages may be used to define a criterion for voltage stability. [36]

For reactive power reserves, a minimum limit can be set, i.e. the reserves must remain above the certain percent of their reactive power output to ensure voltage stability under all contingencies [36]. However, bus voltage limits are used in Nordic countries to assess voltage stability. One method is to set a lower limit for bus voltages which defines the lowest acceptable voltage considered stable. Another method is to define the upper and lower limits which create a range for stable operation.

The voltage limits define a stable operating point, a certain power transmission, in the P-V curve. However, while being near the tip point of the nose curve, voltage may decrease heavily even though the power transmission increases only slightly. Thus, an extra security margin can be utilized to ensure an adequate margin between the obtained transfer limit and the power transmission leading to voltage collapse after a dimensioning fault. [31, p. 174] In practice, the security margin means reducing the maximum transfer limit by a certain, predefined amount.

The basics of defining the transmission capacity utilizing voltage stability criterion are presented by means of P-V curves in Figure 4.3. The pre-contingency curve illustrates the condition before the fault. In the point A, the margin to the voltage collapse point is adequate. However, the condition drops to point B in the post-contingency curve after the fault and then the margin to the voltage collapse point is considerably smaller. In other words, points A and B define the last stable transmission level. To ensure the security during occasional fluctuations in the system, a security margin is utilized. Thus, the final transmission capacity is the power transmission determined by points C and D.

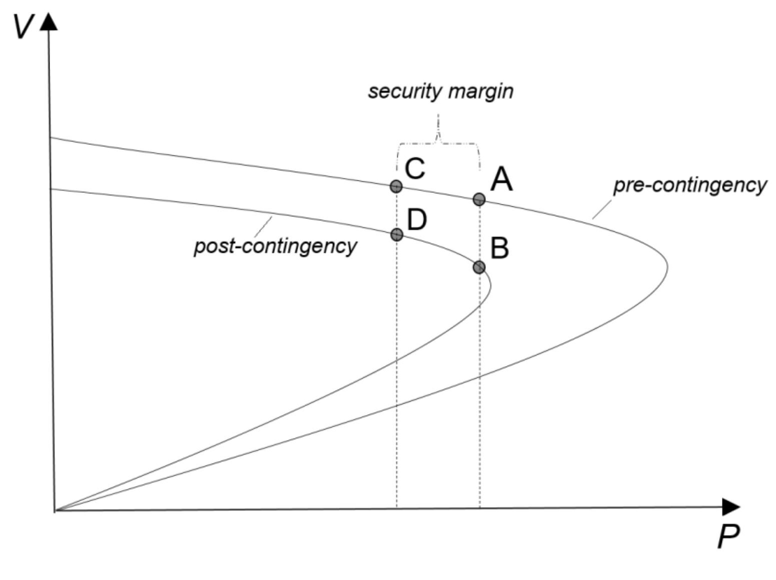

Figure 4.3. *Defining the transmission capacity utilizing the voltage stability criteria. Points A and B determine the last acceptable transmission level. Points C and D determine the final transmission capacity after the reduction of the security margin.*

Fingrid's current criteria for voltage stability are defined as the lowest acceptable voltages. The lowest acceptable voltage in steady-state after a fault in 400 kV network is 370 kV which corresponds to 0.925 pu. The lowest acceptable momentary voltage during post-fault oscillation is 320 kV corresponding to 0.8 pu. [37] To evaluate the power oscillations impact on the transmission capacity, the third method presented above is used by Fingrid. The oscillations must be damped at least 10 percent within 20 seconds after a fault which corresponds to 3-5 swing periods as described in Figure 4.2. In addition, 200 MW security margin is decreased from the achieved capacity. The 200 MW margin covers the inaccuracy of the calculation and it is not the same as the TRM [31, p. 177].

In [38], a transmission capacity calculation method was studied. In the study, a limit for voltage stability was defined as 15 % security margin from P-V curve nose point. More accurately, 15 % margin was defined as minimum and it was not necessary to calculate the exact nose point for every studied case. Instead, the active power in the receiving end bus was increased to $P/0.85$ where P is the maximum load power as none of the security constraints are exceeded. If voltage collapse did not occur and the power flow calculation converged after increasing the load power, the voltage stability margin was considered at least 15 %. If the voltage collapse occurred, the actual nose point was solved and the resulting maximum transfer capacity was reduced by 15 % margin. For rotor angle stability, a limit of 45 degree difference from a reference value was used in the study. [38] In [39], the same constraints as above were utilized in another transmission capacity calculation study.

Tidal energy resources integration in Oregon, United States, was studied in [40] and a case study of the power system security was conducted. In the study, the security criterion for the steady-state voltage was defined so that the voltage deviations were not allowed to exceed 7 % after a single contingency. Concerning transient security, voltage dip was not allowed to exceed 20 % for more than 20 cycles at load buses. Furthermore, the condition must remain stable after all the applied contingencies. These criteria were stated to comply with the practices specified by the local United States authorities. [40, p. 148]

The tidal energy integration in the Republic of Korea was studied in [40] too. In that case, the voltage security criteria were defined as follows: Voltage magnitude range after the disturbance was limited to 0.9 – 1.1 pu, post-contingency voltage deviation was not allowed to exceed 6 % and voltage stability margin must be at least 5 %. Regarding transient security, voltage dip was not allowed to exceed 20 % for more than 20 cycles to prevent the disconnection of the tidal energy resources causing a risk for the grids security and 3 % was defined as the minimum damping ratio for the electromechanical oscillations. [40, pp. 42, 160]

5. RESEARCH AND SIMULATION METHODS

The power system security is studied by computational methods. Investigating the power system's pre- and post-contingency transient and steady-state behavior is called dynamic security assessment (DSA). The concept of DSA is described in Chapter 5.1. In this thesis, the power system is studied by simulations utilizing PSS/E (Power System Simulator for Engineering) software. The simulation software and used calculation methods are presented in more detail in Chapter 5.2.

The studied transmission capacity calculation criteria are described in Chapter 5.3. The simulations are based on the real operating conditions of the Finnish power system, and the cases used in the research were chosen among the real network data and measurements. The cases were chosen so that they represent a diverse collection of network conditions to ensure an extensive investigation of the Finnish power system transmission capacity. The cases used in the study are presented in Chapter 5.4.

5.1 Dynamic security assessment

In addition to the requirement of the power system to fulfill the stability criteria, it must also remain security after the disturbances. Dynamic Security Assessment (DSA) means investigating the transient behavior of the power system after the contingencies, whereas investigating the static behavior of the system after the post contingency fluctuations have been settled is referred to as Static Security Assessment (SSA). However, DSA is often used to refer to both of the previously explained terms. [41, pp. 256-257]

DSA can be performed off-line or online. Off-line DSA means using the model of a specific system condition to analyze the power system operation. In online DSA, real-time data is used to investigate the present system operation. DSA includes three phases: defining the system security criteria and contingencies to be applied, building the system models and completing the analysis. In this thesis, the interest is in voltage stability and damping of electromechanical oscillations. Other factors analyzed by DSA are, for example, the thermal loading and frequency stability. [41, pp. 256-258]

Transmission capacity is traditionally analyzed by off-line DSA. The analysis starts by determining if the investigated system condition fulfills the security criteria after a contingency is applied and if not, which criterion is not fulfilled and which contingency causes the security criteria violation. The initial condition of the analysis is called a base case. If all the security criteria are fulfilled in the base case, the power flow is increased by adjusting some power system variable, such as load or generation, until the security criteria violation occurs. The maximum transmission capacity is the greatest power flow at which no security limits are exceeded after a contingency. [41, p. 265] In this thesis, the power transmission in the cut P1 is increased by shifting loads between southern and northern Finland whereas the full capacity of RAC cut is used in all the simulated situations.

Various methods of performing DSA exist such as power flow analysis, PV analysis, time-domain simulations and eigenvalue analysis. The used method depends on the studied feature. [41, pp. 258-264] Power flow analysis can be used to evaluate voltage stability by creating P-V curves, eigenvalues are exploited to investigate electromechanical oscillation and the time domain simulations are used to assess the transient security of the power system [42]. Power flow analysis and time-domain simulations are utilized in this thesis to examine the static and dynamic behavior of the Finnish power system.

5.2 Calculation methods and network model

The calculations and simulations of this thesis are performed using PSS/E transmission planning and analysis software. The PV analysis feature of PSS/E is used to form the P-V curves which are exploited to analyze the steady-state voltage stability. The PV analysis tool plots the P-V curves during different contingencies for the monitored buses. The weakest bus in each case can easily be determined from the output of the PV analysis.

The power flow calculations are utilized in steady-state analysis. The power flow is solved by iterating the network equations. Full Newton-Raphson and Fixed-slope decoupled Newton-Raphson iteration algorithms are used in this thesis. The iteration ends when the calculation reaches the defined tolerance. Usually, the tolerance is reached in 2-5 iterations [10, p. 151]. If the tolerance is not reached in the predefined number of iterations, the calculation is terminated and the mismatch describes how far the convergence is or how unreliable the result is. The power flow calculations define the condition of the power system in steady-state, for example after the contingencies. However, the power flow calculations are not giving any information about how the condition is achieved but only the end situation is presented.

The dynamic simulations are utilized to gather more accurate information about the behavior of the power system. The dynamic simulations describe the behavior of the power system in a function of time. A disturbance in the power system causes a transient phenomenon. The quantities of the power system such as power flows, voltages and frequency may oscillate during the transient phenomenon which can lead to instability. [10, p. 76] The power flow solution is not giving any information about the transient phenomenon. In this thesis, the dynamic simulations are used to verify the power flow calculations and examine the damping of oscillations. The dynamic analysis is based on a solved power flow case.

In this thesis, the damping of electromechanical oscillations is studied by a signal processing technology called Prony's method or Prony analysis. The Prony's method estimates various quantities in the studied signal, such as frequency and damping of the oscillation modes. The method fits a discrete linear prediction model to the studied signal. Then, the roots of the characteristical equation of the model are found and the amplitude and phase of each mode in the signal are determined. [43] In practice, the Prony's method fits different frequency signals to the inspected curve to find out the dominant oscillation modes. The interest is in 0.3 Hz oscillations because it is the dominant inter-area mode in the Nordic power system as described in Chapter 4.4. The damping ratio of the 0.3 Hz mode is derived from the dynamic simulations utilizing the Prony analysis.

The network model of the whole synchronous system is needed in the dynamic simulations. Thus, the Nordic network model is used in the simulations of this thesis. The Nordic planning model has been made for both low and high load scenarios as the generation resources and loads differ depending on the season of the year. In this thesis, the high load model is used in the winter situations and the low load model in the summer situations. Winter is defined to be from October to March and summer from April to September.

The latest available model of the Nordic power system is used in this thesis. In addition, the real-time situation of the Finnish power system is updated to the model. The real-time situation is based on the measurement data. The loads in the Nordic planning model are modelled as constant power loads for the power flow calculations. For dynamic analysis, the loads are converted to the combinations of the constant power-, constant current- and constant impedance loads.

5.3 Transmission capacity calculation criteria to be examined

Fingrid's currently used criteria for transmission capacity calculation were discussed in Chapter 4.4. The objective of this thesis is to study how the calculated transmission capacity and security margins of the Finnish power system would be affected if different criteria were used.

As described in previous chapters, the transmission capacity of the Finnish and Nordic power system is mainly limited by voltage stability and electromechanical oscillation damping issues. Therefore, the voltage and damping criteria are studied in this thesis. The minimum damping ratio is a commonly used criterion for assessing the electromechanical oscillations. As presented in Chapter 4.4, damping ratios of 3 % and 5 % are often considered as adequate damping. Therefore, the effects that applying damping ratios nearby 3 % and 5 % would have on the Finnish power system are investigated here. The exact damping criteria studied in this thesis are presented in Table 5.1. The 3 % damping ratio is the lowest criterion studied in this thesis because it is often considered as the lowest limit for stable operation as described in Chapter 4.4.

The post-contingency voltage limits are defined based on the TSOs experience of the system operation. It may be possible to adjust the limits especially as the power system develops. Currently, the steady-state minimum voltage limit used by Fingrid is 0.925 pu corresponding to 370 kV. Reducing the voltage limit to 0.9 pu was studied in [44]. It was concluded in the study that despite applying the higher limit would increase the transmission capacity, the current limit should be retained for now as reducing the limit would decrease the voltage stability security margin. However, re-assessment of reducing the voltage limit was suggested as the security margin was predicted to be higher in the future due to upcoming changes in the Finnish power system such as new transmission lines and increasing number of generation resources. The voltage limits studied in this thesis are shown in Table 5.1.

Table 5.1 *Calculation criteria studied in this thesis*

Damping criterion (minimum damping ratio)	6 %	5 %	4 %	3 %
Steady-state voltage criterion (minimum post-contingency residual voltage)	370 kV (0.9250 pu)	365 kV (0.9125 pu)	360 kV (0.900 pu)	355 kV (0.8875 pu)

5.4 Base cases

As described in Chapter 3.2, the state of the power system varies depending on, for example, the season of the year or time of the day. Thus, the base cases used in the research were chosen so that they represent different operating situations. Regarding power transmission in cut P1, power is normally imported from Sweden to Finland during the north to south directional power flow. When power flows from south to north in cut P1, export to Sweden normally occurs for some extent. Basically, the import situations exist during the daytime as the load demand is high in the Finnish power system whereas the export situations take place during the nighttime when the load decreases.

The duration curves of the power transmission in cut P1 for the years 2015-2018 are presented in Figure 5.1. As shown in Figure 5.1, the import situations are much more common. The export hours have increased in later years but still they only comprise roughly 20 percent of the hours in 2018.

According to Finnish Meteorological Institute, the year 2018 was exceptionally dry and warm, whereas the year 2017 was rainier than the average year. The year 2016 was warmer than average and the rainfall was higher than average in winter and summer, the autumn and spring being dry. The year 2015 was record-breaking warm and the rainfall fluctuated around the country. [45]

Regarding the development of the generation portfolio in Finland during the years 2015-2018, the installed wind power capacity was approximately 1000 MW in 2015 whereas in 2017 the amount of wind power had increased to over 2000 MW. In 2018, new wind power capacity was not installed. On the other hand, the condensate power capacity decreased from 1600 MW in 2015 to about 1000 MW in 2016 remaining at that level also in 2017 and 2018. [46]

According to Figure 5.1, the highest power flow in cut P1 has been approximately 2600 MW in the north to south direction and 1700 MW in the south to north direction in the years 2015-2018. While choosing the base cases for the simulations among the import and export situations, the initial power flow in cut P1 was tried to maximize in order to avoid the need for excessively adjusting the base cases to reach the transmission limits.

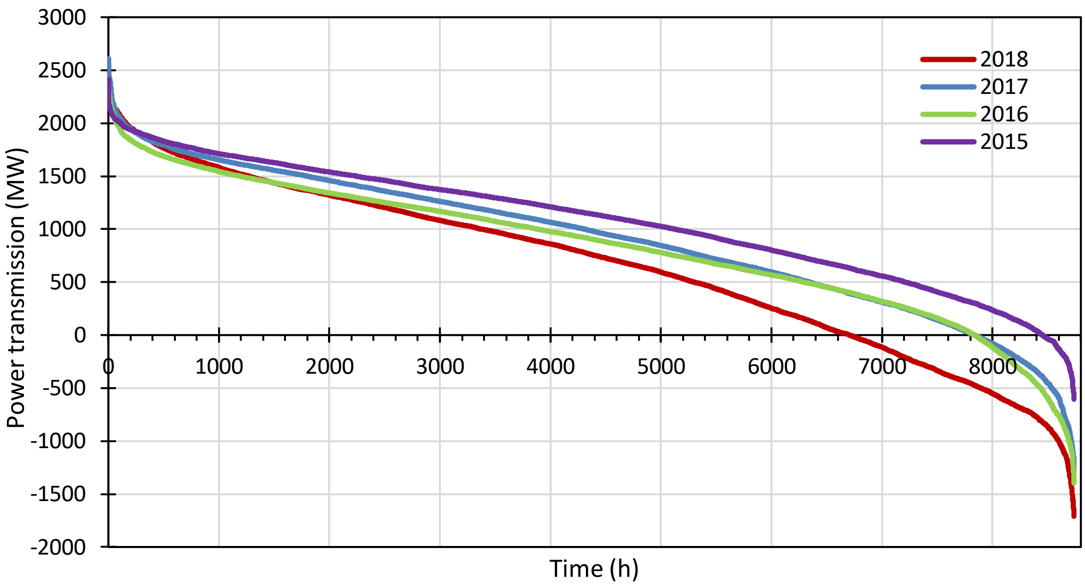

Figure 5.1 *Duration curves of power transmission in cut P1 in 2015-2018. Positive values in the power transmission axis represent import situations and negative values export situations.*

The Finnish power system real-time data of the base cases is from the years 2018 and 2019 because the Finnish transmission grid has been in such form as it is at present since 2018. The base cases presented in Table 5.2 are named based on their characteristic features. The more accurate information about the base cases including the border transfers and loads in the Finnish power system is presented in Chapter 6.

Table 5.2. *Base cases for the simulations. The date and time of the Finnish power system real-time data are inside the braces.*

Import	**Export**
Summer (29.5.2018 19–20)	Summer 1 (25.6.2018 03–04)
Winter (23.11.2018 17–18)	Summer 2 (30.8.2018 02–03)
Wind power peak production (27.9.2018 11–12)	Winter 1 (10.2.2019 04–05)
Hydro power peak production (4.5.2018 13–14)	Winter 2 (17.1.2019 03–04)
Power line outage 1 (28.3.2019 10–11)	Power line outage (26.2.2019 03–04)
Power line outage 2 (27.2.2019 09–10)	Wind power peak production (17.2.2019 03–04)

The summer base cases in Table 5.2 are low load conditions, the summer 1 being a Midsummer night export situation. The summer 2 base case is a rare situation in which export to Sweden occurs in both AC and DC connections between Finland and Sweden. In the real-time data of the other export base cases, power is exported from Finland to Sweden only in the northern AC lines and the Fennoskan HVDC links are set at the export mode manually before the simulations. The winter cases are high load conditions whereas the wind- and hydro power peak production cases are conditions in which the generation of the corresponding resource is at its peak. In the power line outage and power line outage 1 cases one transmission line is out of service in the Finnish power system, whereas in the power line outage 2 case, two transmission lines are out of service.

The contingencies applied in the simulations are the fault of the largest generation unit in the Finnish power system in the import situations and the fault of the largest HVDC link in the export situations. The faults result in the disconnection of the faulty power system component. Both of the contingencies are classified as N-1 conditions, the disconnection of the largest generation unit belonging to FG1 and the disconnection of the internal Nordic HVDC link belonging to FG2 [2, p. 27].

6. RESULTS

The results of the simulations are presented in this chapter. Firstly, the import situations are discussed in Chapter 6.1. The simulation results of the import situations are presented in pairs such as summer and winter, wind and hydro power and the power line outages. The results of the steady-state PV analysis are shown as P-V curves and the graphs of dynamic analysis illustrate the dynamic behavior of the power system during the post-contingency transient event.

The export situations are treated in Chapter 6.2. The export base cases are introduced first. Then, the results of the damping studies are presented in a form of a table as only the P1 power flows associated with each damping criterion were solved in the simulations of the export situations.

6.1 Import situations

The largest generation unit in the Finnish power system will be the Olkiluoto 3 nuclear power plant (OL3). The disconnection of OL3 after a bus fault was used as a contingency in the simulations of the import situations. However, OL3 has not been commissioned yet, hence it was not connected to the grid in the Nordic network model. Therefore, the generation data of the OL3 unit had to be manually updated to the model. Being quite a large unit, the introduction of OL3 affected the power flows in the Finnish power system notably. Thus, the power flow in cut P1 had to be manually adjusted after the introduction of OL3.

After the introduction of OL3, the initial power flow in cut P1 was set at 2400 MW in all import cases to simplify the comparison of the results. The RAC import was at its maximum market capacity of 1500 MW in all the studied situations. The adjustments were made by reducing the border power flows, mainly in the Fennoskan links, and in some cases also by reducing wind power. The Fennoskan links were chosen as they are located nearby the Olkiluoto power plant and thus, the impact of the adjustments on the power flows in the Finnish system were assumed to be minimal. On the other hand, wind power was adjusted as all the Finnish wind generation resources are not yet included in the network model anyway.

The steady-state voltage stability studies were performed using the PV analysis tool of PSS/E. The tool increased the P1 transfer by 20 MW increments and after every increment, the contingency was automatically applied and the power flow was solved. The switched shunts and tap changers were locked during the calculation, i.e. they were not performing adjustments during the PV analysis. The dynamic analysis was carried out after the steady-state analysis. The dynamic analysis was based on the transfer level defined by the 355 kV voltage criterion in PV analysis. In other words, the P1 transfer was set at level defined by the 355 kV voltage criterion before performing the dynamic simulations. The P-V curves and dynamics graphs of the import cases are presented in Chapters 6.1.1–6.1.3. The descriptions of the base cases along with the initial power flows are presented in the beginning of each chapter. A summary of the results is shown in Chapter 6.1.4.

6.1.1 Summer and winter

The results of the voltage stability studies of the summer and winter situations are presented in this chapter. In the summer case, the load in the Finnish power system was 8680 MW and generation 6410 MW. In the winter case, the load was 11880 MW and generation 10550 MW.

The power flows of the main border connections and cut P1 in the summer and winter base cases are presented in Figure 6.1. The power flows in Figure 6.1 represent the initial condition from which the P1 power flow was increased by the PV analysis tool. The RAC import and P1 power flow were the same in both situations. The power flow of the Fennoskan links was from Sweden to Finland in the summer situation and from Finland to Sweden in the winter situation as shown in Figure 6.1. Another main difference was the magnitude of the power import from Russia which was 250 MW higher in summer.

The summer base case represents a typical import situation from early summer. The Olkiluoto 1 nuclear unit was disconnected from the grid due to a yearly revision and the Estlink 2 HVDC connection was also out of service in the summer base case. The longer service outages of the generation units and transmission lines are typically taking place in the summer as the load demand is lower. There were no outages in the Finnish power system in the winter base case and the load in the Finnish power system was relatively high, but not at its peak. A transit flow situation from northern Sweden to southern Sweden through Finland existed in the winter case. That is rather uncommon in the winter, especially when the load demand is high in Finland. When the surplus of hydro power production exists in northern Sweden, some of it can be transferred to southern Sweden through Finland if the internal transmission capacity in Sweden is fully utilized. Typically, the transit flow situation exists in springtime.

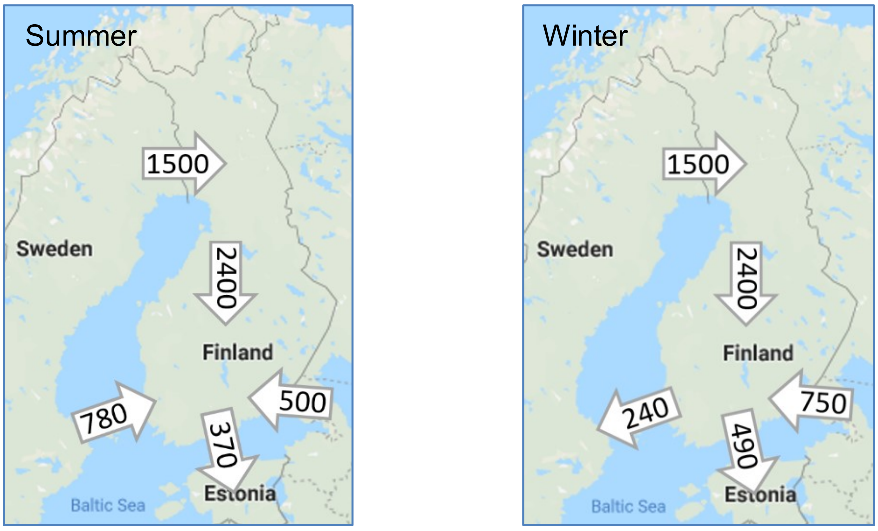

Figure 6.1. *Border transmissions in megawatts in the summer and winter situations. Background map from [47].*

The results of the PV analysis are presented in Figure 6.2. The summer situation was calculated using the Full Newton-Raphson algorithm as using the Fixed-slope decoupled Newton-Raphson algorithm the power flow was not converging in high enough transfer levels to reach the lowest voltage criteria. The winter situation was calculated using the Fixed-slope decoupled Newton-Raphson algorithm because in that case the convergence problems emerged as the Full Newton-Raphson algorithm was used. Figure 6.2 shows the lowest post-contingency voltages of the summer and winter situations as a function of increase in the initial P1 transfer.

The lowest voltage was in the Alapitkä substation in the summer situation and in the Alajärvi substation in the winter situation. The reason for that appeared to be the distribution of the power flows in the Finnish power system. In the winter situation, a transit flow from northern to southern Sweden through Finland existed. In that case, the western P1 lines carry a higher load and thus, the Alajärvi substation located in western Finland was loaded more in the winter situation.

The pre-contingency P-V curves and the post-contingency voltages of both Alapitkä and Alajärvi substations in the summer and winter situations are presented in Appendix A. The pre-contingency voltage in the winter situation is only a little higher than in the summer situation at the beginning of the calculation. However, an apparent difference is shown in the post-contingency voltages in Figure 6.2. According to Appendix A, the difference in the post-contingency voltages can be seen in both Alapitkä and Alajärvi substations. Thus, there is a broader voltage stability problem in the summer situation. In the winter situation, the 0,8875 pu voltage is reached at much higher transmission level than in the summer situation. This is explained by the better voltage support in the winter situation, as the pre-contingency voltage is also greater in the winter situation at the end of the calculation. The better voltage support in the winter situation is due to the greater number of generators in operation and supplying reactive power to the grid.

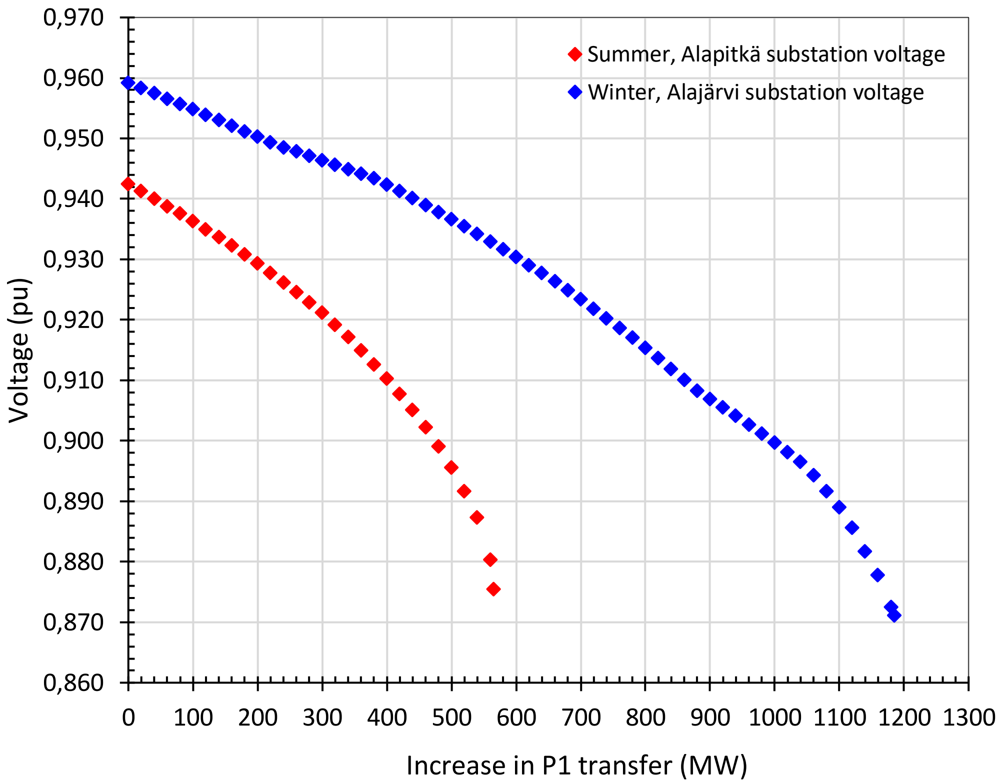

Figure 6.2. *The lowest bus voltages as a function of increase in the P1 transfer in the summer and winter situations.*

The dynamic analysis was performed after the PV analysis. The situations analyzed by the dynamic simulations were chosen from the results of the PV analysis. The transfer level defined by the lowest voltage criterion (0,8875 pu) was used to examine if the transmission capacity is limited by dynamic stability or does the steady-state PV analysis yield a smaller capacity. Thus, the P1 transfer was 2940 MW in the summer situation and 3510 MW in the winter situation in the dynamic simulations. The results of the simulations are presented in Figure 6.3. The lowest voltages were in the same substations as in the PV analysis.

The OL3 unit was disconnected from the grid as a consequence of a fault a second after the beginning of the simulation. As Figure 6.3 shows, the initial voltage level was slightly higher in the winter situation. However, voltage stabilizes to a lower level in the winter situation than in the summer situation. On the other hand, the post-contingency voltage swings are greater in the summer situation. That can be explained by the lower amount of generation resources connected to the grid in summer resulting in the system being prone to greater voltage oscillation.

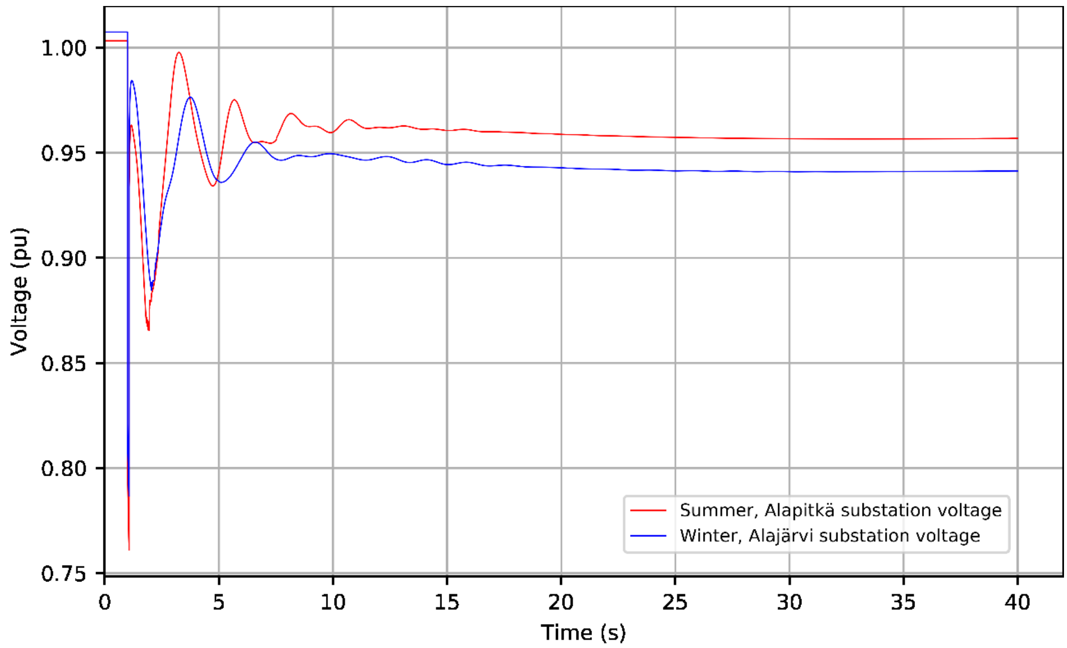

Figure 6.3. *Results of the dynamic simulations of the summer and winter situations.*

According to Figure 6.3, the post-contingency voltage levels out to about 0.96 pu in the summer situation and to 0.94 pu in the winter situation. The voltage dip of the first swing after the fault transient is clearly above the 0.8 pu criterion in both situations. Thus, the dynamic voltage stability is not the transmission capacity limiting factor in these situations. The steady-state voltage criteria are yielding the more conservative estimates of the transmission capacities in both summer and winter situations.

The variance in the results of the dynamic analysis and steady-state calculations comes from the differences in the modelling of the loads and generators. The loads are modelled as constant power loads in the load flow calculations whereas in the dynamic analysis they are converted to the combinations of the constant power-, constant current- and constant impedance loads as discussed in Chapter 5.2. The modelling of the loads was observed to have a remarkable effect on the simulation results in [44]. The dynamic model also includes proper models of the generator's control systems which improve the results of the dynamic analysis.

The effects that applying different steady-state voltage criteria would have on the P1 transmission capacity in the summer and winter situations are presented in Table 6.1. The results are derived from Figure 6.2, and they are shown as a maximum increase in the initial P1 transfer while each voltage criterion is applied. The margins to the voltage collapse points are also presented for each criterion in Table 6.1. The margins were defined based on the P-V curves in Figure 6.2 and the last transfer level achieving convergence in the PV analysis was considered the voltage collapse point. However, the P-V curves in Figure 6.2 do not quite reach the tip point but the situations became numerically unstable in the PV analysis.

Table 6.1. *The maximum increase in the P1 transfer based on the steady-state voltage criteria and the margins to the voltage collapse point for each criterion in the summer and winter situations.*

Operating situation		**Voltage criterion**			
		370 kV (0.9250 pu)	365 kV (0.9125 pu)	360 kV (0.9000 pu)	355 kV (0.8875 pu)
Winter	Increase in the P1 transfer (MW)	680	840	1000	1110
	Margin to the voltage collapse point (MW)	500	340	180	70
Summer	Increase in the P1 transfer (MW)	260	380	470	540
	Margin to the voltage collapse point (MW)	300	180	90	20

The results in Table 6.1 show the major difference between the transmission capacities of the summer and winter situations. The increase in the initial P1 transmission corresponding each voltage criteria is over two times greater in the winter situation than in the summer situation. The margins to the voltage collapse point are also considerably greater in the winter situation.

6.1.2 Wind- and hydro power peak production

In the wind power peak situation, the load in the Finnish power system was 9980 MW and generation 8840 MW. Wind power constituted approximately 1700 MW of the generation capacity. In the hydro power peak situation, the load was 10060 MW and generation 8390 MW. The amount of hydro power production was 2600 MW.

The power flows of the main border connections and cut P1 in both base cases are presented in Figure 6.4. The import from southern Sweden to Finland was some 500 MW higher in the hydro power peak situation. In addition, the export from Finland to Estonia was higher in the wind power peak situation. There was no border transfer from Russia in the hydro power peak case whereas in the wind power situation 370 MW was imported from Russia to Finland.

In the wind power peak situation, the Fennoskan 1 HVDC link was out of service. The real-time data of the wind power peak case was from the end of September, whereas the real-time data of the Hydro power peak case was from the beginning of May when the peak in hydro power production typically takes place. The Olkiluoto 2 unit was not in operation in the hydro power peak situation. Both of the situations represent rather typical operating conditions from the corresponding season of a year. The summer version of the Nordic network model was used in both cases.

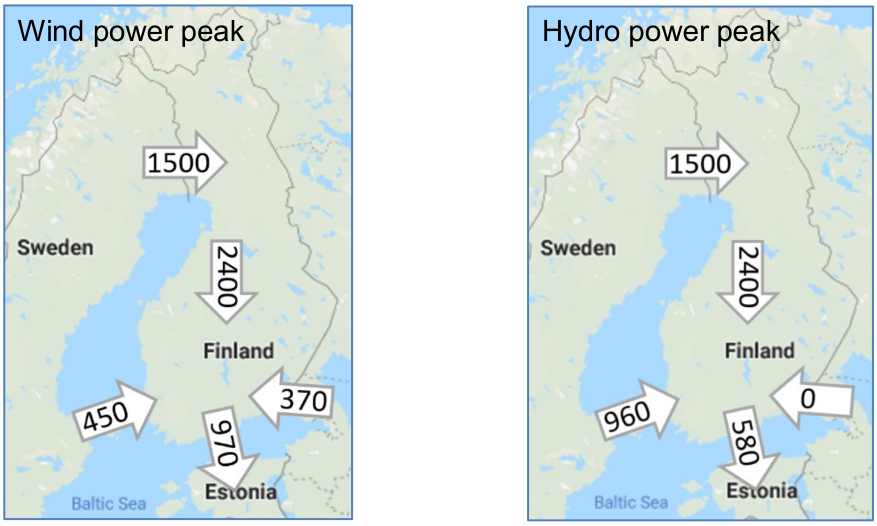

Figure 6.4 *Border transmissions in megawatts in the wind- and hydro power peak situations. Background map from [47].*

The results of the PV analysis are presented in Figure 6.5. The wind power peak situation was calculated using the Full Newton-Raphson algorithm as using that method the convergence was achieved in 40 MW higher transfer than using the fixed-slope algorithm and thus, the voltage collapse was shown more clearly. In the hydro power peak situation, the Full Newton-Raphson algorithm was not converging in high enough P1 transfer to reach the lower voltage limits. Hence, the Fixed-slope decoupled Newton-Raphson algorithm was used in that case.

The lowest voltage was in Alapitkä substation in both cases due to the transfer situation. The Alapitkä substation is normally highly loaded, especially as power is imported to Estonia. In the wind power peak situation, there were more generators in operation in the Finnish power system due to the season of the year. That explains the differences in the curves in Figure 6.5 to some extent. The slope of the hydro power curve changes significantly when the P1 transfer is increased over 400 MW. The main reason for that appears to be the used iteration algorithm as the Fixed-slope decoupled Newton-Raphson method was discovered to produce P-V curves with tighter bends in the middle whereas the curves produced by the Full Newton-Raphson algorithm were smoother as can be seen in Figure 6.5.

An evident difference is visible in the P-V curves in Figure 6.5. The voltage level is higher in the wind power peak situation. According to Appendix A, the difference in post-contingency voltages exist in both Alajärvi and Alapitkä substations. However, the pre-contingency voltages in Appendix A are not differing much in the beginning of the calculation. The main differences between the two situations which may cause the variance in the P-V curves in Figure 6.5 are the lack of Olkiluoto 2 in the hydro power peak situation and the location of the generation units in operation in the situations. The wind turbines are concentrated in western and northern Finland, whereas hydro power is primarily located in northern Finland. Hence, the voltage support in Alapitkä is poorer in the hydro power peak situation. That is demonstrated in Appendix A where the Alajärvi substation post-contingency voltage curve in the hydro power peak situation is close to the Alapitkä post-contingency voltage curve in the wind power peak situation. The 0,8875 pu voltage level is achieved in lower P1 transfer in the hydro power peak situation, which is also explained by the lack of reactive power support.

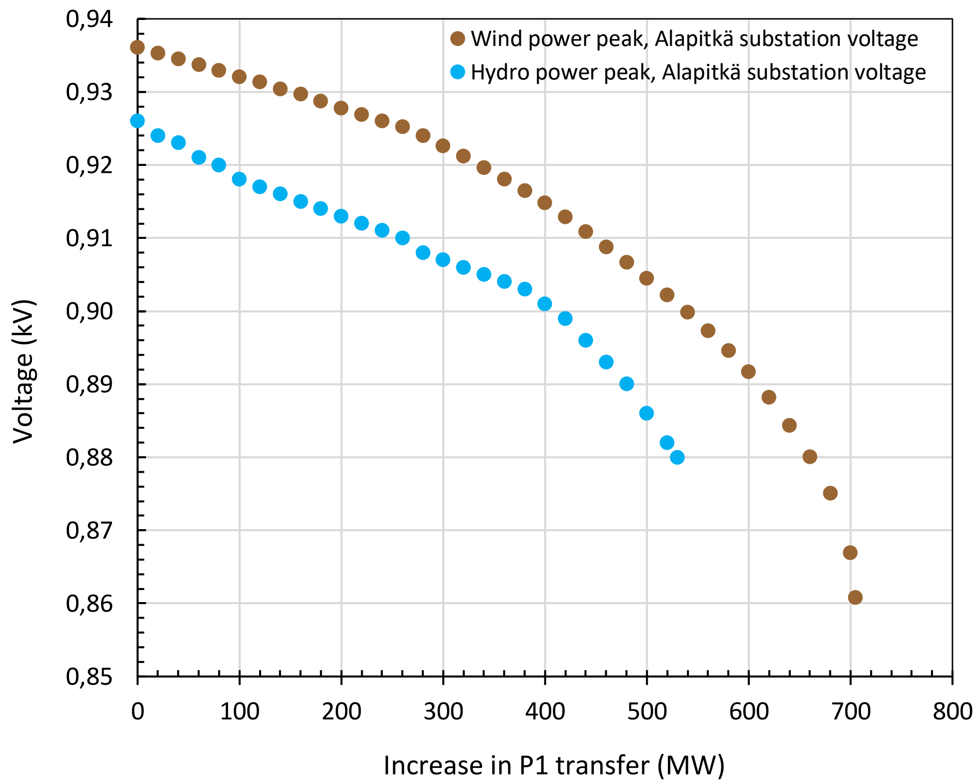

Figure 6.5. *The lowest bus voltages as a function of increase in the P1 transfer in the wind- and hydro power peak situations.*

The results of the dynamic simulations of the wind- and hydro power peak situations are presented in Figure 6.6. In the dynamic analysis, the pre-contingency P1 transfer was 2890 MW in the hydro power peak situation and 3020 MW in the wind power peak situation corresponding to the transfers defined by the 0,8875 pu voltage limit in the PV analysis. According to Figure 6.6, the voltages stabilize to slightly under 0.95 pu at the end of the simulations and the post-contingency first swing voltage is clearly over the 0.8 pu limit in both cases. However, the voltage swings are greater in the wind power situation. The reason for that may be the lower number of generators in operation in the wind power peak situation. On the other hand, the used dynamic model did not include proper models of all the wind turbines which may affect the results of the dynamic analysis. Furthermore, the P1 transmission is greater in the wind power peak situation and thus, the reactive power demand differs between the two situations.

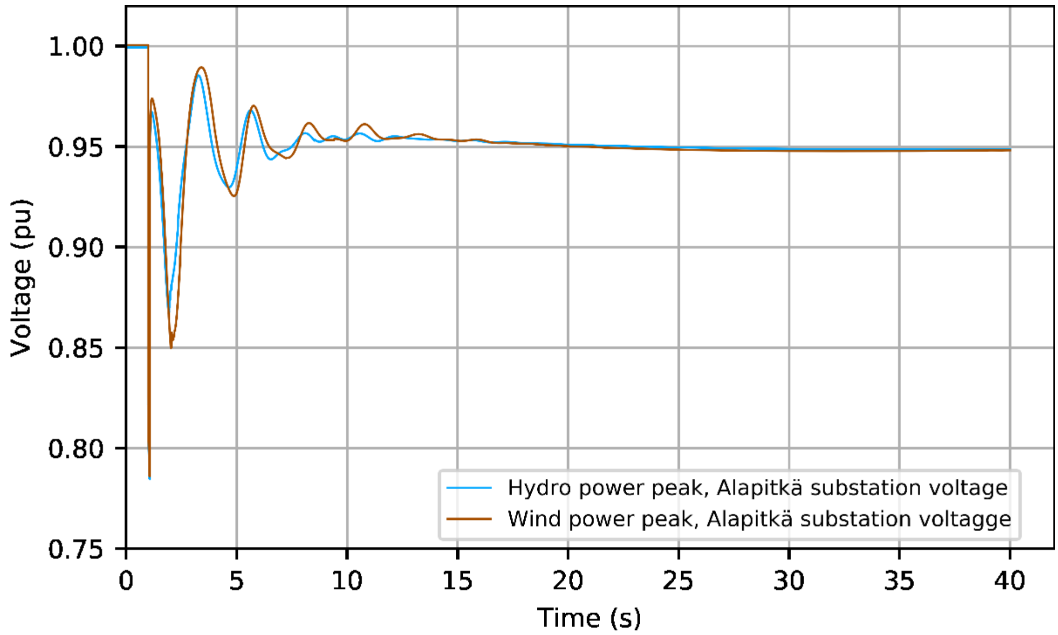

Figure 6.6. *Results of the dynamic simulations of the wind- and hydro power peak situations.*

As in the summer and winter situations, the dynamic voltage stability did not turn out to be the transmission capacity limiting factor in the wind- and hydro power peak situations either. The effects that applying different steady-state voltage criteria would have on the P1 transfer capacity in the wind- and hydro power peak cases are shown in Table 6.2.

Table 6.2. *The maximum increase in the P1 transfer based on the steady-state voltage criteria and the margins to the voltage collapse point in the wind- and hydro power peak situations.*

Operating situation		**Voltage criterion**			
		370 kV (0.925 pu)	365 kV (0.9125 pu)	360 kV (0.9 pu)	355 kV (0.8875 pu)
Wind power peak	Increase in the P1 transfer (MW)	260	430	540	620
	Margin to the voltage collapse point (MW)	440	270	160	80
Hydro power peak	Increase in the P1 transfer (MW)	10	210	410	490
	Margin to the voltage collapse point (MW)	520	320	120	40

The results in Table 6.2 indicate that the P1 transmission capacity corresponding each voltage criterion is higher in the wind power peak situation than in the hydro power peak situation. The difference is larger when the two stricter voltage criteria are applied. When the 360 kV and 355 kV criteria are applied, the differences between the situations decrease. A plausible explanation for the difference is the better voltage support in the wind power peak situation in lower transfer. As the transfer is increased, the reactive power capacity is consumed and the voltages start to decrease faster in the wind power peak situation. The differences in the margins to the voltage collapse points are smaller than the differences in the transmission capacities. The estimated margin is only 40–80 MW higher in the wind power peak situation.

6.1.3 Power line outages

The load in the Finnish power system in the line outage 1 situation was 10800 MW and generation 9250 MW. In the line outage 2 situation, the load was 10870 MW and generation 9850 MW. In the line outage 1 situation, the Huutokoski-Alapitkä power line was out of service. The line is located in the eastern part of cut P1. In the line outage case 2, two power lines were out of service, the first one being the Petäjäskoski-Pirttikoski line in northern Finland and the second the Hirvisuo-Jylkkä line which belongs to the western part of cut P1.

The main border transfers of the power line outage base cases are presented in Figure 6.7. Power flows in the Estonian and Russian border connections are almost the same in both cases. The import from southern Sweden to Finland is higher in the power line outage 1 situation. Both of the situations are taking place in the early spring.

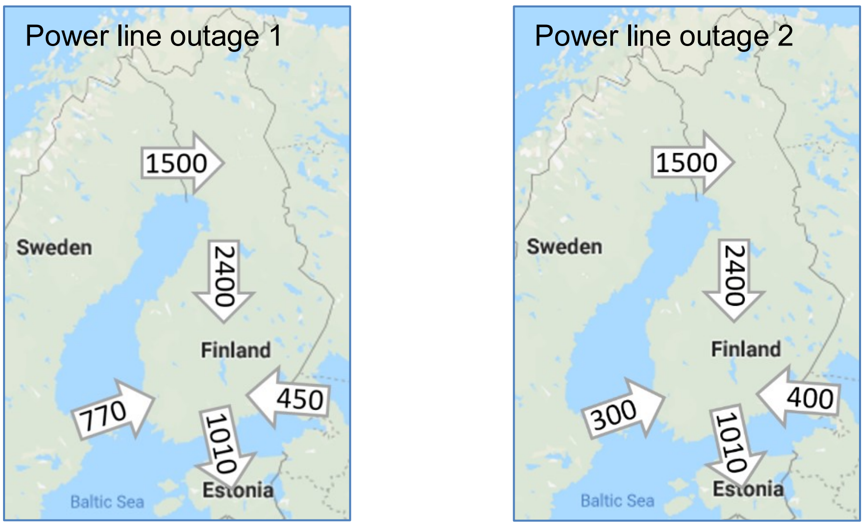

Figure 6.7. *Border transmissions in megawatts in the power line outage situations. Background map from [47].*

The results of the PV analysis are presented in Figure 6.8. Both of the cases were calculated using the Full Newton-Raphson algorithm as it achieved convergence in slightly higher transfers than the Fixed-slope decoupled Newton-Raphson algorithm. However, there were only minor differences between the iteration algorithms.

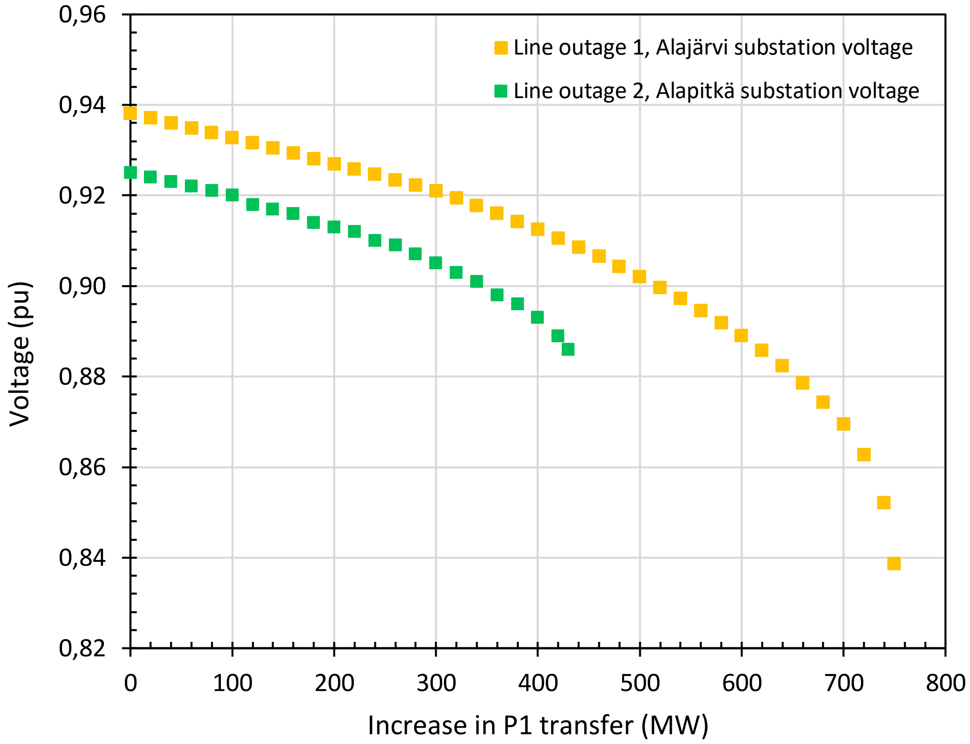

Figure 6.8. *The lowest bus voltages as a function of increase in the P1 transfer in the power line outage situations.*

The lowest voltage in the line outage 1 situation was in the Alajärvi substation. In the line outage 2 situation, the lowest voltage was in the Alapitkä substation. In Figure 6.8, the voltage level is higher in the line outage 1 situation. Similar difference exists also in the pre-contingency curves in Appendix A at lower transfer levels.

The explanation for the lowest voltage in Alajärvi in the line outage 1 situation is the power line out of service in that case. The Huutokoski-Alapitkä line is usually highly loaded, and when it is disconnected, the load is divided into the remaining P1 lines which increases the loading of the Alajärvi substation. On the other hand, the Hirvisuo-Jylkkä line is not usually loaded as much as the other P1 lines. However, the remaining P1 lines are usually already highly loaded and as the Hirvisuo-Jylkkä line is disconnected in the line outage 2 situation, they must carry even higher load. The Alapitkä substation voltage is lower in the line outage 2 situation because the power flow is concentrated on the eastern P1 power line. The disconnection of the Petäjäskoski-Pirttikoski power line was not discovered to have a significant effect on the P1 power flows.

According to Appendix A, the post-contingency voltage in Alajärvi in the line outage 2 situation is also lower than the Alapitkä substation voltage in the line outage 1 situation.

Thus, the voltage stability problem in the line outage 2 situation is broader due to insufficient reactive power support when the P1 lines in operation are highly loaded. For the same reason, voltage drops and the load flow calculation is terminated at lower transfer level in the line outage 2 situation.

In dynamic simulations, the P1 transfer was 3010 MW in the line outage 1 situation and 2820 MW in the line outage 2 situation. The results of the dynamic simulations are shown in Figure 6.9. The lowest post-contingency voltage stabilized to 0.94 pu in the line outage 2 situation and the first post-contingency voltage swing stayed over the 0.8 pu limit in both cases. The voltage level of the line outage 1 situation was approximately 0.925 pu at the end of the dynamic analysis. Currently, Fingrid uses a 0.925 pu limit for the post-contingency steady-state voltage in the dynamic analysis. Thus, the power transfer in the line outage 1 situation corresponding to the 355 kV steady-state voltage criterion would be the last acceptable if the 0.925 pu limit was used in the dynamic analysis.

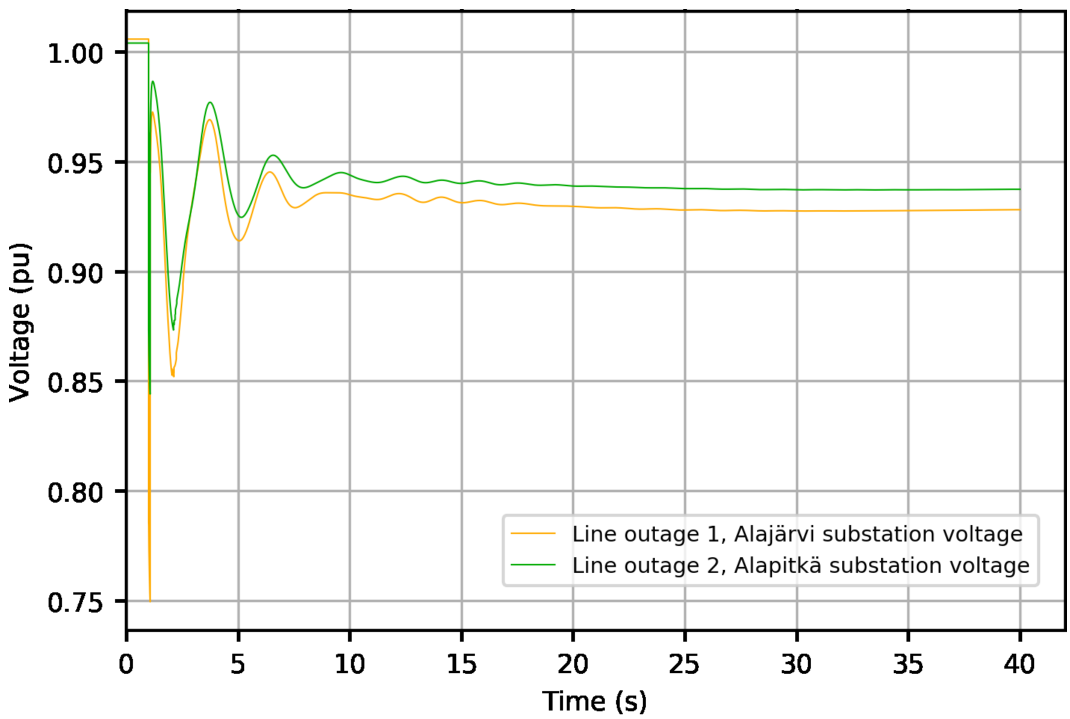

Figure 6.9. *Results of the dynamic simulations of the power line outage situations.*

The amplitudes of the voltage swings in Figure 6.9 are not differing greatly. That is an expected result as the operating situations were quite similar. For example, almost the same number of generators were in operation in both situations. However, the voltage level at the end of the simulations was lower in the line outage 1 situation although the initial voltage was higher in that case as shown in Figure 6.9 as well as in Figure 6.8. The difference is affected by the variance in the modelling of loads and generators. In the dynamic simulations, the control systems of the generators are included and thus, the generators in the Finnish power system may increase power production after the contingency, whereas in the load flow calculations the power balance is controlled by one swing bus.

The dynamic voltage stability did not turn out to be the transmission capacity limiting factor in the power line outage situations either. The transmission capacities defined by the steady-state voltage stability criteria in the power line outage situations are presented in Table 6.3.

Table 6.3. *The maximum increase in the P1 transfer and the margins to the voltage collapse point based on the steady-state voltage criteria for each criterion in the power line outage situations.*

Operating situation		**Voltage criterion**			
		370 kV (0.925 pu)	365 kV (0.9125 pu)	360 kV (0.9 pu)	355 kV (0.8875 pu)
Line outage 1	Increase in the P1 transfer (MW)	240	400	520	610
	Margin to the voltage collapse point (MW)	510	350	230	140
Line outage 2	Increase in the P1 transfer (MW)	0	210	350	420
	Margin to the voltage collapse point (MW)	430	220	80	10

As the results in Table 6.3 show, the transmission capacity in cut P1 is at least 170 MW higher in the line outage 1 situation than in the line outage 2 situation applying any of the steady-state voltage criteria. If the 370 kV limit is used, the difference between the two cases is the greatest as the initial P1 transfer can not be increased at all in the line outage 2 situation in order to fulfill the voltage criterion. The voltage stability security margin is over 100 MW higher in the line outage 1 situation using almost any of the voltage limits. If the 370 kV criterion is used, the difference in the margins is 80 MW.

6.1.4 Summary

The results of the import situations' simulations are summarized in Table 6.4. The transmission capacities corresponding each voltage criterion are shown as total P1 transfers. However, the capacities do not represent the actual technical transmission capacities as only the voltage stability related limitations were studied. To determine the real transmission capacities, other limitations such as the loadability of the transmission lines should also be considered.

According to Table 6.4, the lowest transmission capacities are in the line outage 2 and hydro power peak situations. On the other hand, the transmission capacity is clearly highest in the winter situation. Both of the outage situations are also taking place in winter, but the power line outages are reducing the transmission capacity significantly.

Table 6.4. *Results of the voltage stability studies*

Operating situation		**Voltage criterion**			
		370 kV (0.9250 pu)	365 kV (0.9125 pu)	360 kV (0.9000 pu)	355 kV (0.8875 pu)
Winter	P1 transfer (MW)	3080	3240	3400	3510
	Margin to voltage collapse point (MW)	500	340	180	70
Summer	P1 transfer (MW)	2660	2780	2870	2940
	Margin to voltage collapse point (MW)	300	180	90	20
Wind power peak	P1 transfer (MW)	2660	2830	2940	3020
	Margin to voltage collapse point (MW)	440	270	160	80
Hydro power peak	P1 transfer (MW)	2410	2610	2810	2890
	Margin to voltage collapse point (MW)	520	320	120	40
Line outage 1	P1 transfer (MW)	2640	2800	2920	3010
	Margin to voltage collapse point (MW)	510	350	230	140
Line outage 2	P1 transfer (MW)	2400	2610	2750	2820
	Margin to voltage collapse point (MW)	430	220	80	10

Both the Full Newton-Raphson and Fixed-slope decoupled Newton-Raphson iteration algorithms were used in the steady-state calculations. The used algorithm was chosen based on which one resulted in convergence in higher transfer. It was found that the results were not differing at all in lower transfer levels regardless off the chosen algorithm. However, minor differences were found between the two algorithms at the transfer levels corresponding the 360 and 355 kV voltage criteria resulting in the shape of the P-V curve being slightly different depending on the used algorithm. In some cases, the convergence was achieved in high enough transfers to define the transmission capacities corresponding the 360 or 355 kV voltage criteria only by using the other of the algorithms. All in all, the choice of the iteration algorithm did not prove to have a significant effect on the results.

The security margins of the import situations were examined also enabling the switched shunts to perform adjustments in the PV analysis. The study is presented in Appendix B. The results of the study indicate that Table 6.4 presents a more conservative estimate of the security margins in most cases, i.e. the margins were smaller when the switched shunts were locked in almost all situations apart from the winter situation.

6.2 Export situations

Such as in the import situations, the Olkiluoto 3 power plant was connected to the grid also in the export situations. However, the contingency in the export situations was the disconnection of the Fennoskan 2 HVDC link which was found to cause greater oscillations in the Finnish power system.

The Fennoskan HVDC links were set at full export in all base cases. In addition, the RAC export was set at its 1200 MW maximum technical export capacity. The more precise descriptions of the power flows along with the load and generation in the base cases are presented in Table 6.5. The import from Russia was near the maximum capacity in all the cases. The Estonian import was also near the maximum capacity of the Estlink HVDC links in most cases. In the power line outage situation, only minor import from Estonia existed and in the wind power peak situation about half of the Estlinks capacity was used. The load and generation in the Finnish power system varied between 7000 MW and over 11000 MW corresponding the low load condition in summer and high load condition in winter. There is a balance between load and generation in Finland in the summer and winter cases. In the power line outage and wind power peak cases, a surplus of generation exists in Finland.

Table 6.5. *Border transfers along with the load and generation in the Finnish power system in export situations. Negative value in the border transfers means export from Finland and positive value means import to Finland.*

Operating situation	RAC (MW)	Fennoskan (MW)	Estlink (MW)	Russia (MW)	Load in Finland (MW)	Generation in Finland (MW)
Summer 1	-1200	-1200	980	1300	7000	7230
Summer 2	-1200	-1200	1005	1400	7500	7635
Winter 1	-1200	-1200	990	1380	9240	9415
Winter 2	-1200	-1200	1005	1400	10415	10560
Power line outage	-1200	-1200	90	1250	9900	11250
Wind power peak	-1200	-1200	560	1300	9400	10075

The simulations were performed by setting the initial value for the P1 power flow, running the dynamic simulation and then conducting the Prony analysis to determine the damping ratio of the 0.3 Hz oscillation mode. Based on the damping of the initial transfer, the P1 transfer was either increased or decreased to achieve the 6 % damping ratio. The adjustment of the P1 transfer was made by shifting the loads between the northern and southern Finland. The P1 transfers corresponding to the damping ratios of 5, 4 and 3 % were then solved by further increasing the transfer. The transfer was finally increased to the point the oscillations were no longer damping.

The Prony analysis tool is illustrated in Figure 6.10. The starting position of the analysis was selected so that the nonlinear part in the beginning of the signal was cut out. Typically, the starting position of the analysis was the second oscillation, the time frame being about 5-8 seconds from the beginning of the simulation as shown in Figure 6.10. The reduced-order approximation producing the smallest root-mean-square error between the linear prediction model and the original signal was used if possible. However, the Prony's method may overfit the linear prediction model if the used model order is too high leading to some oscillation modes in the signal splitting into several modes. Therefore, the model order had to be manually optimized for each case minimizing the fitting error and avoiding the root splitting.

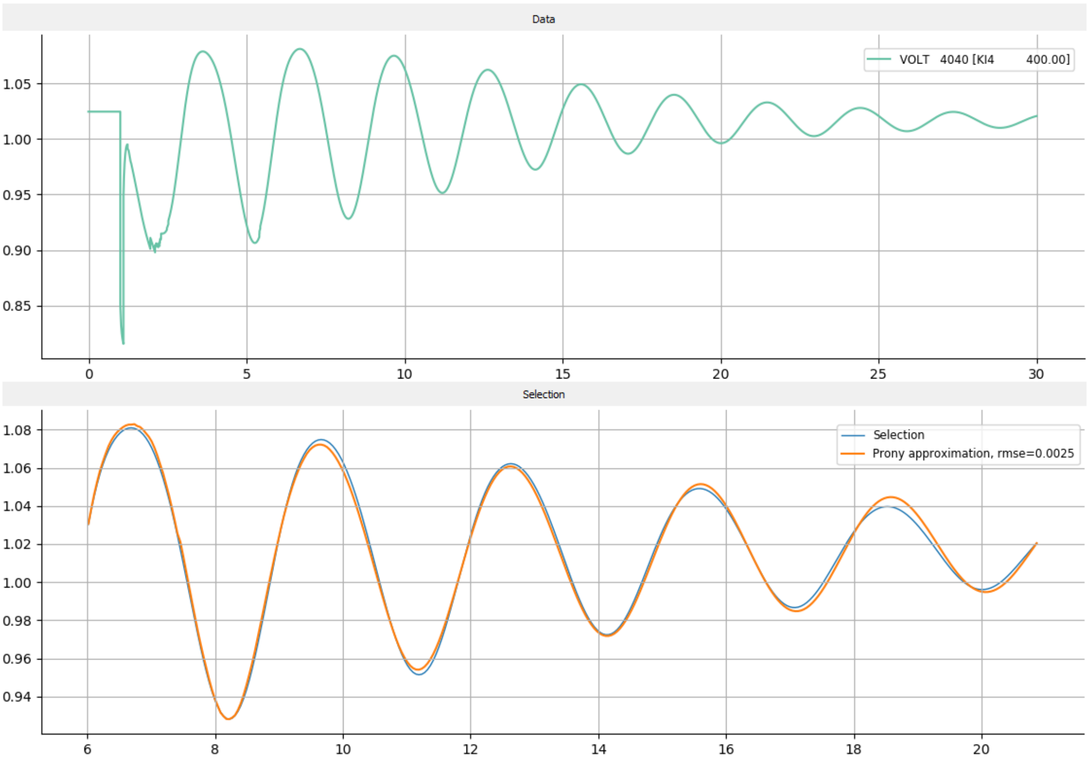

Figure 6.10. *A view of the Prony analysis tool.*

The results of the damping studies are shown in Table 6.6. The P1 transfers along with the margins to the undamped transfer corresponding each damping criterion are presented in Table 6.6 for the studied operating situations. For comparison purposes, the transmission capacities determined by Fingrid's current damping criterion including the 200 MW security margin are also shown in Table 6.6. The summer 1 and summer 2 cases are low load summer situations whereas the other base cases are higher load winter situations. The Keminmaa substation voltage curve was utilized in the damping studies of all export situations.

Table 6.6. *Results of the damping studies using the damping ratios and Fingrid's current criterion.*

Operating situation		Damping criterion				
		6 %	5 %	4 %	3 %	Current
Summer 1	P1 transfer (MW)	1550	1600	1675	1700	1520
	Margin to undamped condition (MW)	175	125	50	25	205
Summer 2	P1 transfer (MW)	2050	2075	2100	2125	1970
	Margin to undamped condition (MW)	140	115	90	65	220
Winter 1	P1 transfer (MW)	1100	1300	1400	1550	1450
	Margin to undamped condition (MW)	600	400	300	150	250
Winter 2	P1 transfer (MW)	1800	2000	2200	2400	2400
	Margin to undamped condition (MW)	850	650	450	250	250
Line outage	P1 transfer (MW)	1800	2000	2100	2250	2150
	Margin to undamped condition (MW)	580	380	280	130	230
Wind power peak	P1 transfer (MW)	1100	1350	1425	1525	1500
	Margin to undamped condition (MW)	650	400	325	225	250

The results indicate that regarding damping, there are differences not only between the summer and winter situations but also between the various situations from the same season of the year. The best damping occurs in the winter 2 situation if the lower damping ratios are examined, and the worst in the winter 1- and wind power peak situations. In both summer situations, damping is in the middle range.

In the summer situations, the increments in the P1 transfers between the different damping ratios are smaller than in the winter situations. In the summer situations, the P1 transfer was increased only 25-75 MW to reach the lower damping ratio. For example, in the summer 1 situation, the difference in the P1 transmission between the 4 % and 3 % damping ratios was only 25 MW. In the winter situations, the minimum increase was 100 MW but in most cases the increment was greater than that.

If the damping ratios are examined, another significant difference between the summer and winter situations indicated by the result in Table 6.6 is the magnitude of margins to the undamped transfer. In the winter situations, the margins are clearly greater than in the summer situations. In the summer situations, the P1 transfer corresponding to the 3 % damping ratio is within a few dozen megawatts of the unstable transfer. In the winter situations, the smallest margin applying the 3 % criterion is 130 MW occurring in the line outage situation as the P1 transfer is 2250 MW. However, if the magnitude of the margin is compared in relation to the transfer level, the winter 1 situation is worse because the P1 transfer corresponding to 3 % damping ratio is only 1550 MW the margin being 150 MW in that case.

In the summer cases, there is a major difference in damping between the two operating situations. If the winter situations are examined, the results in Table 6.6 indicate that damping is relatively similar in the winter 1 and wind power peak situations. The same concerns the winter 2 and line outage situations. However, there are some differences in the magnitudes of transfers corresponding to the stricter damping criteria in the similar damping conditions.

To examine the possible causes of differences in damping between the operating situations from the summer and winter seasons, the number of synchronous generators equipped with power system stabilizers (PSS) in operation was counted. The number of generators equipped with PSS in the studied situations is presented in Table 6.7.

Table 6.7. *The number of generators equipped with power system stabilizers in operation in the export situations.*

Operating situation	Summer 1	Summer 2	Winter 1	Winter 2	Line outage	Wind power peak
Generators with PSSs and their maximum power	17 (4965 MW)	17 (5692 MW)	21 (5618 MW)	24 (6250 MW)	25 (6309 MW)	20 (5555 MW)
> 100 MW generators with PSSs and their maximum power	8 (4427 MW)	11 (5197 MW)	11 (4625 MW)	13 (5435 MW)	11 (5450 MW)	10 (4601 MW)

According to Table 6.7, the number of synchronous generators in operation equipped with power system stabilizers in the winter situations appears to correlate with damping in those situations. In the winter 1 and wind power peak situations, the P1 transmission capacities are equal and so are the number of generators equipped with power system stabilizers. A similar trend is visible in winter 2 and line outage situations. However, in the summer situations the difference in transmission capacities is not associated with the number of generators in operation equipped with PSSs as the count of generators is the same in both summer 1 and summer 2 situations.

To examine the differences in the transmission capacities of the summer situations, the features of the synchronous generators in operation were compared. It turned out that the larger generators contribute damping more than the smaller ones. As Table 6.7 shows, the count of the generators equipped with PSSs is the same in both summer situations, but there are larger generators in operation in the summer 2 situation and thus, the damping is better leading to higher transmission capacity. A similar trend is visible in the winter situations if the number of over 100 MW generators is compared. The transmission capacities are higher in the winter 2 and line outage situations and the larger generators were also in operation then. When the largest generators equipped with power system stabilizers were in operation in the Finnish power system, damping was considerably better in the studied situations.

In the line outage situation, the number of generators equipped with power system stabilizers in operation is the largest among the export situations. The largest generators are also in operation in that case as can be seen in Table 6.7 if the count and the maximum power of over 100 MW generators are compared. However, the P1 transmission capacity is lower than in the winter 2 situation if the 3 % and 4 % damping criteria are applied. The reason for that is the higher loading of the remaining P1 transmission lines as the Hirvisuo-Jylkkä line is out of service leading to worse damping.

7. DISCUSSION

As predicted, the import and export transmission capacities of the cut P1 turned out to have a major variance due to different capacity limiting phenomena. The transmission capacity is limited by angle stability in the export situations whereas voltage stability is the limiting factor in the import situations.

The transmission capacities presented in Chapter 6 of this thesis are not market capacities, neither are they proper technical capacities, as only voltage- and angle stability were considered in the research ignoring other limitations in the studied situations. The results also hold good only in the studied situations. However, the results indicate the differences in the transmission capacities in various conditions using different calculation criteria.

7.1 Voltage criterion

The dynamic voltage stability did not prove to be a transmission capacity limiting factor in any of the import situations. Thus, the steady-state analysis yielded the more conservative estimations of the transmission capacities in the studied situations. However, the dynamic analysis is considered producing more realistic results due to the more advanced modelling of the power system. The results indicate the reduction of the voltage criterion would increase the transmission capacity but decrease the voltage stability security margin. That is in line with the findings in [44].

The research confirms that the P1 transmission capacity from south to north varies depending on the operating situation. The season of the year appeared to have a noticeable influence on the transmission capacity mainly due to different generation resources and loads in the grid. The major difference in the results is between the transmission capacities of the summer and winter situations, the transmission capacity being over twice higher in winter than in summer. Voltage level appeared to decrease slower in the winter situation than in the other studied situations. The power line outages appeared to reduce the transmission capacity bringing it closer to the summer situations given that the line outages were taking place in winter. The wind- and hydro power peak situations were not found to have a major influence on the transmission capacity compared with the summer situation.

Concerning security, the voltage stability security margins turned out to have minor variance between the different operating situations although the transmission capacities varied more. On the other hand, if the switched shunts were enabled to perform adjustments in PV analysis, the margins were in most cases greater than if the switched shunts were locked. According to the results of this thesis, the security of the Finnish power system does not appear to be endangered if the currently used voltage limit was slightly reduced. However, the security margins of the 355 kV voltage limit proved to be such small in the studied situations, that using 355 kV as a calculation criterion should be treated with caution.

According to Fingrid's Specifications for the Operational Performance of Power Generating Facilities, the type D generators, which means over 30 MW generators or generators connected to 110 kV or higher voltage network, must remain connected to the grid in voltage fluctuations between 90–105 % of the nominal voltage. The generators are allowed to disconnect from the grid without time margins if the voltage drops below 90 % of the nominal voltage. [48, pp. 11, 47–48] In 400 kV network, the operation range of the generators is 360–420 kV. Thus, using the 355 kV voltage level as a transmission capacity calculation criterion might cause a risk for the disconnection of some generators in consequence of a contingency. The disconnection of the generators could lead to voltage instability especially as the voltage stability security margins appeared to be fairly small using the 355 kV voltage limit.

In this thesis, the lowest voltages in the 400 kV network were in the Alapitkä and Alajärvi substations. However, no generators are connected to those substations, but the nearest generators are connected to the lower voltage network distant from the 400 kV substations. Thus, the voltage level in the nearest generator bus is likely not to decrease as much as in the 400 kV bus due to the voltage support of the generator and the impedance of the lower voltage network between the generator bus and the 400 kV bus. Hence, the voltage stability security margin in the generator bus is likely to be greater than in the 400 kV bus which decreases the risk of the generation disconnection.

The majority of loads and generation are connected to lower than 400 kV network. Thus, the actual voltage levels or margins to the voltage collapse point in the grid connection points of the loads and generators cannot be determined by calculating the voltages in the 400 kV network. However, the voltage level in the 400 kV network currently acts as a transmission capacity calculation criterion sufficiently well especially when the shunt reactors are locked during the load flow calculation. If the switched shunts are performing adjustments during the calculation, the voltage level may remain rather high also near the voltage collapse. In that case, the voltage level alone does not provide adequate information about the state of the power system.

The loads were modelled as constant power loads in the steady-state load flow calculations and the voltage dependence of the loads was not taken into account. In reality, the loads normally reduce when the voltage level decreases resulting in the decreasing of the power transfer. Thus, the security margins included in the lower voltage criteria in Table 6.4 are likely to be somewhat greater in reality. On the other hand, the slope of the generator voltage controllers is not modelled in the used simulation model. Therefore, the reactive power support of the generators is better in the simulations than in reality.

7.2 Damping criterion

The results indicate that a major difference in damping exists between the summer and winter situations. The summer situations turned out be more sensitive regarding damping compared with the winter situations, the margins to the undamped condition being considerably smaller in the summer situations. The difference between the security margins of the summer and winter situations poses a challenge in choosing a consistent damping ratio to be used in the transmission capacity calculation.

If the current damping criterion of Fingrid is compared with the damping ratios studied in this thesis, the results in Table 6.6 show that the margins to the undamped transfer are more consistent using the current criterion. If the damping ratios are used, the margins vary more between various operating situations. The results indicate that if the damping ratios of 6, 5 or 4 % are applied, the security margins are greater than in the currently used criterion in the winter situations. However, the stricter damping ratio is used, the more the calculated transmission capacity decreases.

If the 3 % damping criterion was used as a transmission capacity calculation criterion, the transmission capacities would be quite similar to the capacities determined by the current calculation criterion but the security margins turned out to be smaller especially in the summer situations. On the other hand, the security margins of the summer situations proved to be smaller even if the 6 % damping criterion was used. Thus, regardless of the applied damping ratio, adding an extra security margin should be considered in the summer situations.

To define a separate criterion for the summer situations, the summer situation should be unambiguously defined. In this thesis, the summer situation was defined to be from May to September, but the time based classification is not necessary the most appropriate due to the variance of loads and generation resources in the power system. For example, the load and generation were under 8000 MW in both summer situations in this thesis. In the winter situations, the load and generation were over 9000 MW. However, it is possible to exceed the 9000 MW value also between May and September.

Another possible mean to define separate calculation criteria for the operating conditions of poor and moderate damping would be the combination of the damping ratio and the generator capacity equipped with power system stabilizers. The capacity of the larger (over 100 MW) generators equipped with PSSs in the Finnish power system was under 5000 MW in the situations of poor damping. When the damping was better, the PSS capacity was over 5000 MW. The combination of PSS capacity and damping would also eliminate the need to define the damping criterion based on the season of the year.

Concerning wind power, the results did not indicate the damping to be directly proportional to the amount of wind power in the power system. However, if the share of wind power grows in the future and the large conventional power plants equipped with power system stabilizers are not in operation during the peak in wind power production, damping issues may emerge.

The import from Russia to Finland was near the maximum capacity in all the studied situations. Thus, it would be beneficial to examine how does the volume of import from Russia affects damping. Concerning the used methodology, the Prony's method causes some uncertainty in the results. The choice of the starting point in the Prony analysis affects the resulting damping ratio. The impact was tried to minimize by starting the analysis at as similar point as possible in all the studied situations. Another source of error in the Prony analysis is the nonlinearity of the examined signal. The Prony's method fits a linear prediction model for the studied signal, and if it the signal is highly nonlinear, the results may become distorted. By cutting out the most nonlinear part of the signal, the distortion was aimed to be minimized.

8. CONCLUSIONS

By analyzing different operating situations, this thesis has shown how choosing the transmission capacity calculation criteria for voltage stability and damping of the electromechanical oscillations would affect the transmission capacity and security margins of the Finnish power system. Decreasing the voltage criterion and changing the currently used damping criterion to a damping ratio were examined in this thesis.

The research illustrates that decreasing the voltage criterion would increase the transmission capacity but reduce the security margin. However, the results show that a sufficient security margin is included in the 365 kV voltage criterion. The margins included in the 360 kV criterion were also moderate in the studied operating situations. Therefore, decreasing the voltage criterion slightly does not appear to endanger the security of the Finnish power system.

However, 360 kV is the lower limit for the operation range of the generators and thus, the voltage criterion can not be set to below 360 kV. The 365 kV voltage limit appears to be a decent calculation criterion as the security margins to the voltage collapse point were sufficient in the simulations. In addition, the margins from the 365 kV limit to the 360 kV limit were 90–200 MW in the situations examined in this thesis.

Further research is needed to make certain that the voltage stability security margin is sufficient in various situations if the currently used voltage criterion was reduced. The security margins appeared to be smallest in the summer situation. In addition, the calculation settings were observed to have an effect on the calculated security margins due to the voltage collapse point mainly occurring at higher transfer level if the switched shunts were enabled to perform adjustments instead of keeping them locked.

A major difference in damping was found between the summer and winter operating situations. The summer situations were observed to be more sensitive regarding electromechanical oscillations, i.e. a minor increase in the power transfer worsened damping clearly in the summer situations. The currently used damping criterion was found to correspond to a damping ratio of 3–4 % in the winter situations. In the summer situations, the transmission capacities and security margins determined by the current calculation criterion were closest to the ones determined by the 6 % damping ratio.

Damping in the summer situations is the limiting factor when choosing the calculation criterion. Based on the results of this thesis, the security margins included in the current damping criterion are more consistent in comparison with the margins included in the damping ratios in varying situations. Using the 3 % damping ratio can not be recommended in the summer situations due to the remarkably small security margins. At least, adding an extra security margin should be considered then.

The 5 or 6 % damping ratios appear to be more reasonable calculation criteria even though the security margins included in the summer situations were still smaller than using the current calculation criterion. In addition, using the 5 or 6 % damping ratios as a calculation criterion would decrease the transmission capacity in the winter situations. Hence, the introduction of different calculation criteria for various operating situations should be considered or alternatively keeping the current damping criterion in use is recommended.

For further research, the thermal limits of the transmission lines should be examined to define the real transmission capacities. In addition, the difference between the load flow calculations and dynamic analysis in the voltage stability studies would be beneficial to examine. This thesis proved the load flow calculations produce more conservative transmission capacities due to simpler modelling. However, it was not examined how large the difference is or if the difference is consistent in various situations. The behavior of the network model in extreme conditions should also be verified. The situations examined in this thesis were brought near the limits of the system operation, and it would be valuable to examine if the behavior of the model matches reality near the system collapse point.

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APPENDIX A: P-V CURVES

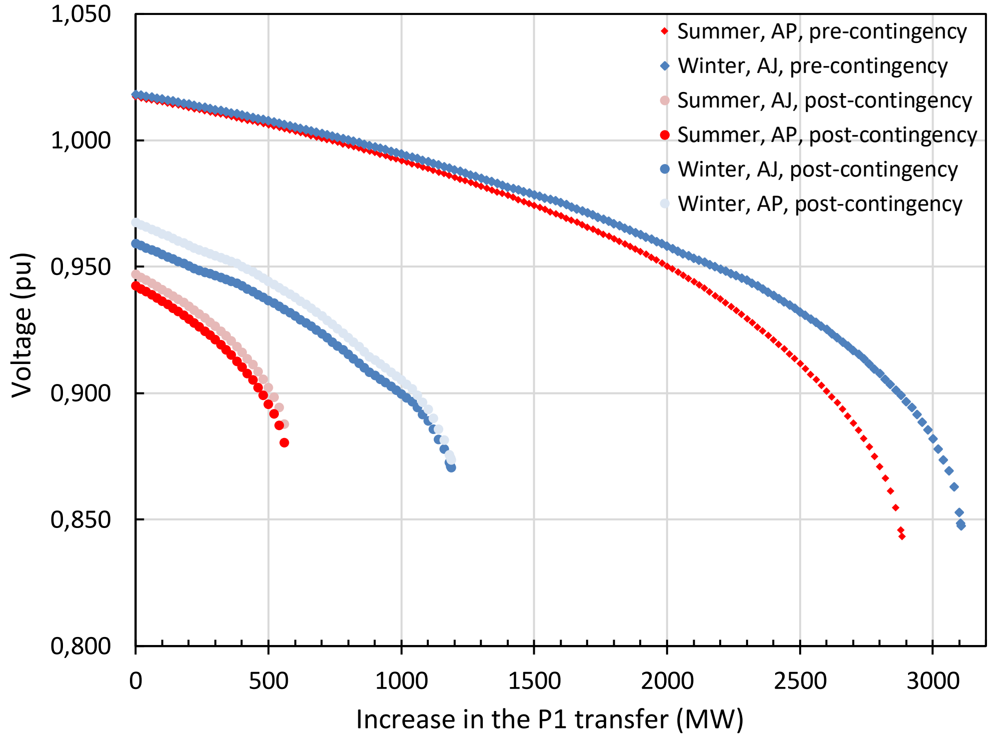

Figure A.1. *Pre- and post-contingency P-V curves of the summer and winter situations. AP and AJ refer to the Alapitkä and Alajärvi substations.*

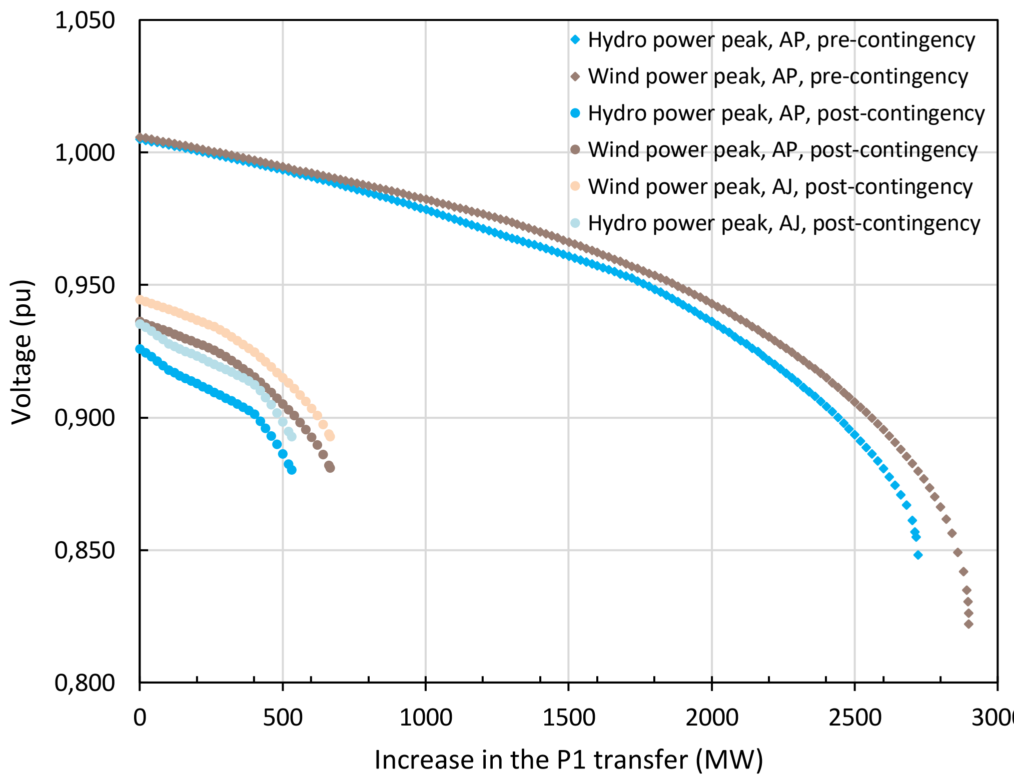

Figure A.2. *Pre- and post-contingency P-V curves of the wind- and hyrdro power peak situations. AP and AJ refer to the Alapitkä and Alajärvi substations.*

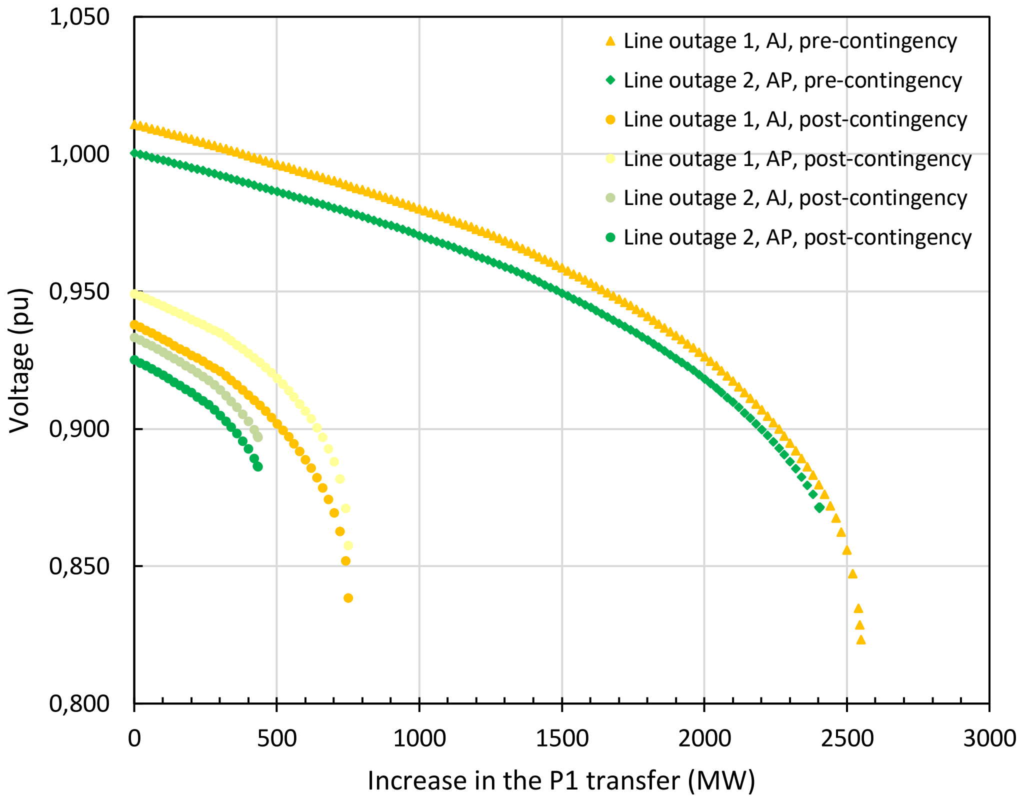

Figure A.3. *Pre- and post-contingency P-V curves of the power line outage situations. AP and AJ refer to the Alapitkä and Alajärvi substations*

APPENDIX B: PV ANALYSIS WITH SWITCHED SHUNTS ENABLED

The steady-state voltage stability PV analysis was carried out enabling the switched shunts to perform adjustments to examine how the P-V curves and especially the security margins would change if the shunt reactors were adjusting the reactive power consumption as the loading of the transmission lines increases. The results are presented in Figure B.1. In the hydro power peak situation, the power flow calculation was not achieving convergence even if the P1 transfer was not increased at all from the initial value. Hence, the hydro power peak situation is lacking in Figure B.1.

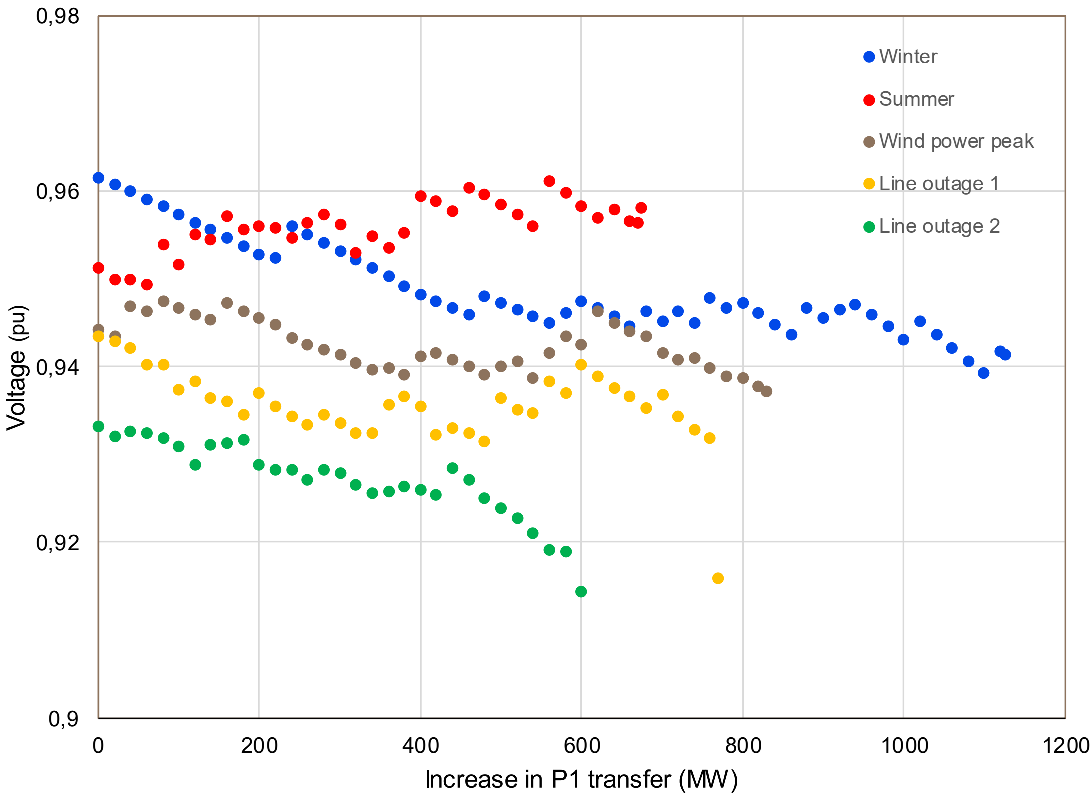

Figure B.1. *P-V curves of the import situations when the switched shunts were performing adjustments.*

The convergence was achieved in high enough transfer to show the voltage collapse point only in the line outage 1 and line outage 2 situations. However, if the P-V curves in Figure 6.8 and in Figure B.1 are compared, voltage remains over the 0.925 pu limit in much higher transfer level in Figure B.1. Voltage remains higher in greater transfer also in the other situations when the switched shunts are enabled. The margins to the voltage collapse points derived from Figure B.1 are shown in Table B.1. The P1 transmission capacities in Table B.1 were determined in Chapter 6.1, and the voltage collapse points were considered being the last P1 transfers achieving convergence in Figure B.1 even though the actual voltage collapse points could not be defined as the calculation was not achieving convergence in high enough transfer levels due to numerical instability.

Table B.1. *Margins to the voltage collapse points as the switched shunts were performing adjustments. "-" means that the margin could not be defined.*

Operating situation		**Voltage criterion**			
		370 kV (0.9250 pu)	365 kV (0.9125 pu)	360 kV (0.9000 pu)	355 kV (0.8875 pu)
Winter	P1 transfer (MW)	3080	3240	3400	3510
	Margin to voltage collapse point (MW)	440	280	120	10
Summer	P1 transfer (MW)	2660	2780	2870	2940
	Margin to voltage collapse point (MW)	410	290	200	130
Wind power peak	P1 transfer (MW)	2660	2830	2940	3020
	Margin to voltage collapse point (MW)	570	400	290	210
Hydro power peak	P1 transfer (MW)	2410	2610	2810	2890
	Margin to voltage collapse point (MW)	-	-	-	-
Line outage 1	P1 transfer (MW)	2640	2800	2920	3010
	Margin to voltage collapse point (MW)	520	360	200	150
Line outage 2	P1 transfer (MW)	2400	2610	2750	2820
	Margin to voltage collapse point (MW)	600	390	250	180

Due to convergence issues in the simulations, the margins to voltage collapse points in Table B.1 are minimum values. The voltage collapse was achieved only in the line outage 1 situation, and in the line outage 2 situation the voltage level dropped to under 0,925 pu. Most of the margins in Table B.1 appear to be greater or the same compared with Table 6.4. The margins are smaller only in the winter situation in Table B.1. However, the actual voltage collapse point of the winter situation could not be defined and the voltage remains relatively high in the last transfer level in Figure B.1. On the other hand, the line outage 1 situation shows that the voltage collapse may occur suddenly. Although most of the margins in Table B.1 are greater than in Table 6.4, further research is needed to confirm the results.